A
REPORT
TO THE
PETROLEUM DIRECTORATE
GOVERNMENT OF NEWFOUNDLAND AND LABRADOR

PRELIMINARY INVESTIGATION for the PRODUCTION AND TRANSPORTATION OF GAS from the HIBERNIA FIELD

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To Include
Hibernia-Bay Bulls
Pipeline Route

EPI Resources Limited
JOHN BROWN Offshore Limited

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1.0 INTRODUCTION AND SUMMARY

1.1 INTRODUCTION

This Report, entitled "Preliminary Investigation for the Production and Transportation of Gas from the Hibernia Field", is the result of a request for proposals issued by the Government of Newfoundland and Labrador, Petroleum Directorate in September, 1981. Work on the preliminary investigation commenced on the 7th December, 1981.

The Petroleum Directorate terms of reference for the Study remain as follows:

- To determine the oil production requirements regarding gas re-injection.
- To describe a reasonable gas gathering system.
- To describe the production platform gas processing equipment assuming the liquids are extracted on site.
- To determine any on site power requirement using gas as a fuel.
- To determine the nature and volume of marketable gas.
- To provide details of a gas pipeline to shore: size, wall thickness, materials, pressure, routing problems, etc.
- To estimate capital and operating costs of a gas pipeline.
- To determine the net cost to shore of the gas.
- To estimate the effect of gas production from other fields near Hibernia on the net costs.

In discussion with the Petroleum Directorate, it was agreed that, within the above terms of reference, the principal objectives of the Study are two-fold:

i) To gain an overview of the systems and equipment requirements for production and pipeline export of gas from the Hibernia Field; and

ii) To gain sufficient information on landed gas volumes and development costs to enable a meaningful economic evaluation to be carried out by the Directorate.

It was further agreed that while considerable depth may be developed in each area of the Study, the limited extent of data and information generally available on the Hibernia development did not justify a highly detailed investigation at this time, particularly in view of the relative short duration of the Study (three months) and the limited value of the work ($50,000).

The Study as performed therefore provides the Petroleum Directorate with an overview of the production and transmission of gas from the Hibernia Field concentrating on four priority areas, namely:

i) General gas systems and gas equipment descriptions;
ii) Additional definition of the main gas pipeline;
iii) Landed gas volumes and characteristics; and
iv) Capital and operating cost assessment of the general gas systems.

It has been necessary to consider the requirements for gas production and transmission as an integrated part of the overall development concept since it is not considered valid simply to "add-on" gas facilities to a development concept designed for the export of crude oil by offshore tanker loading together with gas disposal by re-injection. Although only an implied part of the scope of work, therefore, considerable effort has been expended in adopting a reasonable, integrated Field Development Concept for Study purposes and for future planning guidance by the Directorate.

It is emphasized, however, that the concept adopted is not the result of detailed investigation, comparison and evaluation of the alternatives for development of Hibernia. This must be the result of a full Field Development Planning Study based on a systems approach and extending from the reservoir, through the total production and export system to the economic modelling of the Field.

The use of Floating Production Facilities in the preliminary investigation is a basic premise adopted since the inclusion of a fixed structure would readily permit the integration of gas export facilities, their integration with floating systems presenting a more difficult problem.

The development concept adopted is considered reasonable for the integrated gas facilities, but is not necessarily the preferred concept which may emerge from the Field Development Study. A number of alternative approaches could be envisaged which would have served the Study purposes equally well, but with a different set of advantages and disadvantages compared to the concept adopted. Further, the lack of detailed data concerning the risk of iceberg scour damage within the Hibernia location did not permit the evaluation of the absolute (statistical) and relative risk of the alternative concepts to allow a meaningful preference to be stated.

Definition of the overall facilities requirements, as adopted for Study purposes, for the Hibernia Field, is therefore presented herein with the objectives of:

i) Providing a discussion base against which to review the integration of gas transmission facilities; and

ii) Permitting the assessment of an order-of-magnitude total development schedule and cost so that the addition of the gas transmission facilities may be placed in its proper perspective.

In particular, the scope of this investigation does not include consideration of reservoir performance; production data being provided as input to the Study. Due to certain anomalies within the available data, however, commentary is made on the possible variation in basic data which may emerge as the result of detailed reservoir analysis and the compilation of a consistent reservoir development and depletion approach. As such data is confirmed, it will be essential to review the premises of this preliminary investigation to appreciate the impact on the development concept as adopted and the conclusions drawn.

Following this introductory Section and definition, in Section 2, of the key premises and assumptions upon which the Study is based, and the approach taken to execution of the work, the Report is presented in seven main sections as follows:

* definition of the overall Field Development Concept adopted for Study purposes and supporting commentary on the overall development (Section 3 refers).
* definition of a production and export systems design philosophy considered suitable for the export of both oil and gas from the Hibernia Field (Section 4 refers).
* discussion on principal components of the floating production facilities adopted for Study purposes which may provide a reasonable means of implementing the development concept (Section 5 refers).
* consideration of the gas usage requirements and general systems availability which leads to the determination of average versus peak stream day production rates (Section 6 refers).

- discussion on the key requirements for a gas transmission system in terms of its configuration and outline specification within the overall Field Development Concept adopted for Study purposes and with regard to handling additional quantities of gas from outside the Hibernia Field (Section 7 refers).
- consideration of an overall development plan/schedule which may obtain given the Field Development Concept as adopted for Study purposes (Section 8 refers).
- assessment of capital and operating costs for the adopted development concept, including the gas transmission system (Section 9 refers).

Due to the preliminary nature of the investigation, considerable discussion of the critical areas of the development is included as appropriate.

The emphasis of the main Study is the consideration of a southern offshore pipeline route making a landfall at Trepassey Bay on the Avalon Peninsula, Newfoundland. Subsequent to completion of the main Study, brief consideration has been given to a shorter, more direct route to a Bay Bulls, Newfoundland landfall. Information relating to this alternative is incorporated into this Report as appropriate.

1.2 OVERALL CONCLUSIONS

As a result of this preliminary investigation, it is considered that it is technically feasible to integrate gas transmission facilities within a Hibernia Field Development Concept involving floating production platforms (FPP's) and crude oil export by offshore loading.

The acceptability of a submarine gas pipeline subject to risk of damage by iceberg scour over a route where it is not considered feasible to provide adequate depth of cover beneath the seabed depends on defining an acceptable level of such risk in technical and economic terms. This being outside the scope of this preliminary investigation the acceptability of such a submarine gas pipeline cannot be commented upon.

The key engineering areas which will need to be resolved do not relate to the pipeline itself, which is considered conventional, but to the interface between the pipeline and the FPP production deck. Considerable innovative design and engineering is required in terms of riser systems and with regard to the inclusion of subsea pig/sphere launching into the gas pipeline to displace any liquids which may drop out during operation. The development of such systems is considered to be a reasonable extension of current technology.

Based on the assumptions used in the Study, and adopting a southern gas pipeline route via a Trepassey Bay landfall, the additional capital costs for gas export and transmission from the Hibernia Field to Long Harbour, Newfoundland are in the region of $950 MM (1st January, 1982 dollars) and represent approximately a 23% increase in total field development capital costs (without gas export, excluding pre-project and development drilling costs).

Associated operating costs for gas export would be in the region of $40 MM (1st January, 1982 dollars) per year during peak gas transmission. However, these incremental costs should not be considered in isolation of the total economic projections for the Field.

Subsequent to completion of the main Study, brief consideration of a northern gas pipeline route, via a Bay Bulls landfall from Hibernia to a Long Harbour termination, indicates a gas transmission system capital cost in the region of $770 MM (1st January, 1982 dollars). This represents aproximately a 19% increase in total field development capital costs (without gas export, excluding pre-project and development drilling costs). Associated operating costs for the northern gas export system would be in the region of $33 MM (1st January, 1982 dollars) per year during peak transmission.

Subject to detailed route survey data, detailed engineering and establishment of the absolute and relative risk of damage to either system, the northern pipeline route is seen to offer significant capital cost reductions, in the order of $180 MM, compared to the longer southern route.

Further, based on the assumptions used in the Study, the construction of a submarine gas pipeline to shore is not considered to be a critical item in the overall Field Development Plan/ Schedule, given the exclusion of deep burial for iceberg scour protection.

Finally, it is essential to establish knowledge of the onshore utilization of Hibernia gas in order that the specification of gas for transmission may be defined. Should the transmission of "dense phase", "rich" gas prove unacceptable, the development concept adopted for Study purposes will need to be reviewed.

1.3 OVERALL DEVELOPMENT CONCEPT - SUMMARY

1.3.1 Reservoir and Production Characteristics

As basic data input to the Study, four floating production centres are adopted with annual average daily oil and gas production rates as follows:

Production Facility	Average Annual Daily Production Rates MBOPD	Average Annual Daily Production Rates MMSCFD
Avalon North	50	20
Avalon South	90	30
Hibernia North	50	100
Hibernia South	90	100
FIELD TOTAL	280	250

Gas production is defined as gas available for re-injection or potential export after deducting fuel gas usage.

The above rates are adopted for Study purposes but give rise to some inconsistencies and anomalies in terms of:

- gas/oil ratios (relatively low for the Avalon zone with considerable variation between the two Hibernia zone centres);
- relative production rates between producing zones (inconsistent in that the Avalon zone oil production may be twice that from the Hibernia zone);
- re-injection of gas in the early years of Field life may increase the overall GOR;

- number of production, water or gas injection wells which may be required (too few in input data);
- overall level of production (field life in excess of 40 years possible at rates given).

It is considered essential that a consistent reservoir model be developed and correlated with the Study input data to assess the implications on the Study.

Limited data is available at this time regarding produced fluid characteristics and thus definition of the facilities required is based on experience of similar process schemes.

1.3.2 Aspects of Oil/Gas Utilization

Landed gas specifications have not been stated and therefore the principal options for both offshore and onshore gas utilization are reviewed for information. Principal options offshore are considered to be:

- Liquefied Natural Gas;
- Methanol; and
- Power Generation,

while principal options onshore for Hibernia associated gas alone are considered to be:

- Industrial Consumption;
- Power Generation;
- Liquefaction for Re-Export.

Since Hibernia gas is principally associated gas produced with the oil, it is not considered a reliable source in isolation for non-interruptible uses, e.g., domestic consumption, and is considered insufficient in quantity to support significant petrochemical uses. Whatever the facilities offshore and the utilization onshore, flaring cannot be eliminated, only minimized, since there is always an essential base load and since operational variations must be allowed for.

1.3.3 Development Alternatives

Following a review of possible development alternatives within the premise of floating production facilities, the functional requirements of each production centre were defined for Study purposes as follows:

	Production Centre Locations			
	Avalon		Hibernia	
Function	North	South	North	South
Production Facilities	*	*	*	*
Water Injection Facilities	*	*	-	-
Gas Export/Injection Compression	-	-	-	*
Produced Water Treatment	*	*	*	*

This arrangement has benefits with respect to achieving a reasonably equitable distribution of topside payload and space requirements between production centres and has the advantages of centralized gas handling facilities and minimum duplication of equipment. The arrangement has the disadvantages of an increased number of seabed transfer lines, and hence risk of damage without deep trenching, increased operational complexity and marginally reduced availability as compared to a concept with independent FPP's.

In the absence of the opportunity for detailed comparison and evaluation of the alternatives, semi-submersibles of conventional configuration are adopted as floating production platforms (FPP's). Semi-submersibles have been proposed by others and exhibit excellent motion characteristics but have deck payload and space constraints, which result in a large FPP structure size for relatively moderate deck payloads.

With respect to crude oil storage, a moored tanker approach is adopted, due to its application elsewhere, but its possible inapplicability for long term, efficient operation in the severe Hibernia sea states is noted. Fixed structures are excluded within the premises of the Study.

Given the application of FPP's, extensive subsea equipment requirements arise.

1.3.4 Conceptual Facilities Configuration

At least four FPP's are considered necessary to contain topside loads within reasonable levels, say, 10,000 to 15,000 tons. A fifth FPP is a possibility if deck payloads at individual production centres give rise to excessively large structures or if centralization of, say, water injection and gas treatment/compression proves attractive.

Six, 12-slot Clustered Manifold Centres are adopted, to provide a reasonable unit size for systems control and throughputs and is suited for directional well targets. A number of separate, vertically drilled wells are likely to be required, particularly for water injection, the capability to tie-back, say 16, satellite wells being included. This total of 88 wells is considered a reasonable but minimum number given the production and injection requirements of the Field.

The CMC's are not located directly beneath the FPP's since more than four CMC's are considered necessary and remote location offers the benefits of:

- optimum CMC location independent of FPP location;
- concurrent drilling/production operations;
- reduced FPP deck payload due to elimination of workover facilities (and unnecessary duplication of equipment);
- reduced risk of wellhead damage due to dropped objects;

but with a possible increase in the potential risk of damage by iceberg scour. Also, loss of vertical access to the wells results in a need for a separate drilling/workover rig. Well control and handling of low pour point crude will be more difficult but may be operationally controlled by suitable systems design. Since, due to the number of wells required, the workover activity is likely to be continuous, the availability of a dedicated separate workover rig(s) is considered necessary in any event. At this time the benefits of remote CMC's are considered to outweigh the disadvantages but detailed investigation may prove otherwise

The CMC's are tied-back to their respective Riser Manifold Bases beneath each FPP, which in turn are connected to the FPP production decks by Riser systems.

The floating oil storage system and shuttle tanker mooring/loading terminals are assumed to be located outside the perimeter of the Field to the south, the final location being decided by detailed risk analysis of drifting tankers potentially colliding with the FPP's and possibly each other.

The CMC's and Riser Manifold Bases are assumed to be located in seabed excavations to reduce the risk of damage due to iceberg scour. This assumption must be justified by further investigation.

1.3.5 Critical Areas of the Development Concept

The principal critical areas are as follows:

- * the need for a full Field Development Planning Study to determine the preferred method of development. The development concept for this Study is only one alternative available;
- * the need for a consistent reservoir model providing data on which to base the Field Development Planning Study;
- * a fifth FPP may be necessary; as may alternative distribution of functions between FPP's, including the option of independent production centres (include as part of Field Development Study);
- * increased, but at this time undefinable, possible risk of damage by iceberg scour (collect additional data, statistically define iceberg risk, and include as part of Field Development Study);
- * application of conventional flowline trenching techniques, e.g., jetting, to Hibernia soils must be established (collect additional data and carry out detailed study);
- * detailed safety review and design accidental event analysis required as development plan emerges;
- * phased development of the Field should be considered (as opposed to the total development approach adopted for Study purposes) with the possible benefits of:
  - improved reservoir knowledge
  - improved environmental knowledge
  - an incremental approach to an unprecedented major subsea production development
  - gaining lead time to further evaluate the application of fixed structures and possible onshore gas utilization
  - improved industry and Government confidence levels that year round production and export is reliable in a hostile environment

In overall terms, a total systems approach must be adopted in order to ensure that all aspects of the development are investigated and that individual components combine to form a coherent, integrated development plan. Typically, a Field Development Planning Study not only achieves its own objectives, but may fulfill an "umbrella" function in co-ordinating the study of individual aspects of the development.

1.4 PRODUCTION AND EXPORT SYSTEM DESIGN PHILOSOPHY - SUMMARY

1.4.1 Conceptual Process Flow Scheme

Given the adoption of a combination of centralized functions and equitable facilities distribution between production centres, the approach is taken that the process facilities should be as simple as possible to minimize weight and space requirements. Further, it is assumed that all injection water would be sourced from sea water throughout the life of the Field (since the full demand must be met from this source in early years when produced water quantities are low) and that all produced water would be treated to better than 50 ppm and discharged overboard. This also avoids any problems of water incompatibility.

Water injection facilities are divided equally between the two Avalon FPP's (150,000 BWPD each), since this is where the maximum demand arises. A subsea injection water header system is provided between the two Avalon Riser Manifold Bases and to the Hibernia Riser Manifold Bases, to meet variations in demand and to achieve possible utilization of "watered-out" production wells for injection purposes.

Medium pressure gas off the separators from Avalon North and South and from Hibernia North would be transferred to Hibernia South for compression for re-injection or possible export. Hibernia South is used for this purpose since it is relatively close to the anticipated gas injection well targets for the Hibernia North and South zones.

A simple 3 or 4 stage oil/gas separation philosophy is adopted, the number of stages depending on reservoir pressure. Produced water is removed at all initial stages with an electrostatic treater prior to the crude oil stabilization vessel which produces crude oil for export within the required vapour pressure limits. At this time, to reduce weight and space requirements, single trains have been used for each production centre, but detailed study may indicate a preference for dual trains for the higher production rates at Avalon South and Hibernia South.

Injection gas discharge pressures are envisaged to be in the region of 6,000 psi. To minimize additional equipment requirements for gas export, a two stage high pressure gas compression system has been adopted, the interstage discharge pressure providing a suitable head for "dense phase" gas transmission, say 2,700 psi.

Fuel gas offtake is from a suitable medium pressure source, provision of an alternative fuel source for emergency power also being required.

1.4.2 NGL Utilizaton

Considerable process simulation/optimization will be required during detailed design, the process scheme adopted for Study purposes not having the benefit of such analysis. Given the scenario of oil export by tanker and gas export by pipeline, considerable engineering effort is required to determine the extent of NGL's produced and their optimum utilization.

Since no required landed gas specification can be defined at this time, and since the worst case as regards NGL's is where high quality, specification ("dry") gas is required onshore, the philosophy of exporting "rich" gas in the "dense phase" has been adopted. Accepting this philosophy, minimal quantities of unexportable NGL's are anticipated, and their preferential utilization as fuel may be considered.

A number of relatively simple methods are available for improving stabilized crude recovery without the need for fractionation columns. The application of such methods is a matter for basic engineering.

1.4.3 Produced Water Treatment

Proven water treatment packages are available to maintain the oil content of any water discharge to sea below an average of 40 ppm to 50 ppm and below 100 ppm for 96% of the time. Such levels are generally acceptable in the offshore industry, a design level of 5 ppm to 20 ppm being applied.

1.4.4 Gas Pipeline Operating Philosophy

The "dense phase" transmission of "rich" gas is adopted for Study purposes. Single phase "dry" gas is considered too restrictive at this time since additional offshore hydrocarbon dewpoint control equipment is required. Two phase flow is considered too inefficient and unpredictable for the distances and quantities of gas involved.

The philosophy adopted increases the amount of onshore processing required but minimizes offshore facilities. Even with the transmission of "dry" gas, onshore processing to some extent would be required to produce high quality specification gas for domestic use.

A condensing gas is therefore transmitted, the minimum landfall pressure being set to limit liquid drop-out in the line to reasonable levels, which in turn establish the frequency with which the line must be pigged/sphered to displace liquids.

Given an inlet pressure of 2,700 psig, a minimum outlet pressure in the "just pigged", "dry" condition of 1,500 psig has been adopted, with a 300 psi margin on outlet pressure reduction during operation due to liquid build-up. This will typically limit sphering frequency to once very few days.

1.5 FLOATING PRODUCTION FACILITIES - SUMMARY

1.5.1 Topsides Facilities

Application of the conceptual process design philosophy to each of the four FPP's results in the following Deck Payload summary which includes:

- Production Equipment and Main Utilities
- Accommodation and Hotel Services
- Helideck
- Flaring Equipment
- Structural Steel (local)
- Bulks

and a contingency of 30%:

Production Centre	Topside Weight (Long Tons)	
	Dry	Operating
Avalon North	5,940	7,450
Avalon South	6,680	8,450
Hibernia North	5,990	7,330
Hibernia South	8,070	9,590

Marine systems may amount to a further 1,500 tons to 2,000 tons with a vertical mooring load at the operating draught of, say, 300 tons. Riser handling and diving systems may add a further, say, 540 tons with the riser deployed.

Conceptual layouts for each FPP may require the following areas on two main decks with additional space allocation above the main decks:

Production Centre	Main Deck Area Requirements
Avalon North	2 x 33,905 ft.^{2}
Avalon South	2 x 37,675 ft.^{2}
Hibernia North	2 x 31,485 ft.^{2}
Hibernia South	2 x 37,675 ft.^{2}

The layouts as developed include consideration for safety both of the personnel and the facilities.

With respect to the topsides facilities, the critical design aspects requiring definition will be:

- specified average and peak design throughputs of production and water/gas injection systems
- composition of produced fluids
- variations in the above over the life of the field including water production
- required specification of the landed oil/gas product, especially with respect to establishing the acceptability of "dense phase", "rich" gas transmission
- FPP safety systems and operational procedures

1.5.2 Support Structures

It is considered that, for purpose designed, semi-submersible FPP's of conventional configuration, the Deck Payload as summarized above may comprise 25% of the displacement of the FPP at the operating draught. Subject to detailed engineering therefore, the size of the Hibernia FPP's need be no larger than largest, severe environment, exploration rigs currently under construction, i.e., having displacements in the order of 40,000 tons, given the facilities adopted for Study purposes. For the facilities considered here, adequate deck area may be made available on rigs of such size. Payloads in excess of, say, 10,000 tons will require larger vessels, but reasonable increases in operating displacement can be readily designed.

Any variation in the distribution of functions between production centres will revise this preliminary conclusion.

It is preferable that converted rigs are not used so that the optimum design is achieved with respect to structural integrity, motion response and long term safety against the specific characteristics of the Hibernia location. Considerable structural analysis and model testing will be required to achieve this optimum.

The design life of the facility must be in excess of, say, 30 years if it is to match the productive life of the Field.

1.5.3 Subsea Systems and Risers

The extent to which subsea production equipment is required for the adopted Field development concept is without precedent world-wide. The concept requires:

- a minimum of six, 12-slot Clustered Manifold Centres
- four Riser Manifold Bases
- four FPP riser and riser handling systems

- up to 16 (optional) satellite wells
- riser bases for oil storage and mooring/loading risers
- significant numbers of in-field flowlines and transfer lines

Considerable innovative design and engineering development will be required and it is essential that an integrated systems design approach is adopted to ensure the compatibility of all aspects of the equipment. The required systems are considered to be a reasonable extension of current technology, however, but the magnitude of the undertaking must not be underestimated, possibly requiring considerable lead time for fulfillment.

It is desirable that in-field lines be capable of being pigged as required, particularly for crude lines where pour point problems may arise, and for gas lines where hydrates may form. It is, however, essential that the main submarine gas line be capable of being pigged/sphered operationally to displace liquids. It is likely that, for the main gas line, a subsea pig/sphere launching system will need to be developed since it is not readily envisaged that such large pigs could be run from the FPP production deck. Such a system should also be feasible to develop.

Riser design will be of critical importance since its limiting operational sea state controls the overall availability of the floating production system. Integral risers, as opposed to risers where individual lines are retrievable, may be preferred due to ease of handling but the overall riser design is an area for detailed consideration. No significant technical problems are envisaged however in the relatively moderate water depths at Hibernia. The inclusion of an emergency disconnect system is, of course, essential due to iceberg collision risk and other factors, e.g., unexpectedly severe weather.

1.5.4 In-Field Flowlines and Transfer Lines

The development concept adopted requires in the order of 45 miles of flowlines and transfer lines including:

- CMC/Riser Base Bundled Flow/Control Lines
- CMC or Riser Base to Satellite Well Bundled Flow/Control Lines
- Injection Water Transfer Lines
- Medium Pressure Gas Transfer Lines
- Injection Gas Transfer Lines
- Oil Export Lines

To reduce the risk of damage from iceberg scour, deep trenching of the lines is desirable. The achievable depth of cover will depend on the engineering properties of the soil at the location and the applicability of conventional trenching equipment.

The CMC's/Riser Bases, etc., must be protected from damage in the event that a flowline or transfer line is dragged at a point close to such subsea equipment.

Protection from trawl boards and light anchors will depend on the extent of natural backfill of the trench. From this point of view, the lines should be laid in pre-defined "corridors" and the general area should be restricted with respect to marine activities. Dedicated mooring systems may be installed for platform supply vessels and other construction vessel mooring arrangements must be carefully designed and implemented.

1.5.5 Crude Oil Storage System

Between seven to ten days storage is likely to be required to reduce downtime due to the effect of weather on the shuttle tanker mooring/loading system. This requires in the order of 2 MM barrels storage. Typically, a 225,000 ton dwt. tanker may accommodate 1 MM bbls. (assuming 40% segregated ballast). Two such vessels would, therefore, be required at Hibernia although the combination of storage volume, number of shuttle tankers and number of mooring/loading terminals must be the result of computer simulation of the system operation.

Tanker based storage systems have been adopted for Study purposes by virtue only of their proven application elsewhere, although not in such severe environments. Detailed investigation of tanker applications, and alternative vessels, such as Mobil's semi-submersible tank, is required, particularly with respect to mooring aspects.

Shuttle tanker mooring/loading terminals should be of the severe environment type, preferably permitting self-mooring by the shuttle tanker (e.g., an Articulated Loading Column). Over-stern or alongside mooring to the storage vessel may be arranged for use in good weather.

Approximately eight to ten shuttle tankers (say, 130,000 ton dwt.) may be needed if a 1,000 mile voyage radius is required.

1.5.6 Construction and Installation

Construction of the FPP semi-submersible hulls may be conventionally undertaken at suitable shipyards or construction sites. The philosophy of complete installation of topside equipment and maximum pre-commissioning of systems at the "dockside" should be adopted. This will minimize offshore construction effort and hence cost. Similarly, the storage systems and mooring/loading terminals may be constructed at suitable shipyards/construction sites.

The in-field flowline bundles may be fabricated at a suitable site in Newfoundland for installation by off-bottom tow or similar techniques.

A critical aspect of the development is the apparent need to protect subsea installations, e.g., CMC's, Riser Manifold Bases, etc., from iceberg scour by excavating "glory holes", say, 50 ft. deep. Such excavations are high cost and time consuming, requiring the construction of purpose-built excavation systems. Insufficient data is available at this time to statistically establish the level of such risk and to thereby carry out a detailed technical and economic comparison between deep "glory holes" and alternative protection methods, such as caisson completed wells at wide spacing tied back individually to a manifold centre, low profile wellhead equipment and/or combination berms/excavations. The potential cost savings indicate that such detailed study is essential. The excavation method adopted for Study purposes is based on a clamshell grab system, a prototype of which has at least been tested, but which is likely to have a low rate of spoil removal.

Trenching of in-field flowlines has been mentioned above and depends on detailed investigation of soils and available trenching machinery.

The overall installation sequence will require several years and is critically influenced by the need for excavations in advance of CMC/template installation such that sufficient lead time is provided for pre-drilling of development wells.

Apart from installation of the subsea equipment, flowlines and transfer lines, other installation requirements for the development are few, little work being required to float out and install the completed FPP's. The FPP's may require piled anchors for long term security of moorings and these will require an extensive, although simple, construction period spanning possibly two seasons.

Suitable phasing of the FPP construction and installation schedule may be achieved by installing two FPP's per season over two seasons, but this should be verified by detailed planning.

1.5.7 Critical Areas of the Floating Production Facilities

A summary of the key critical areas relating to the Floating Production Facilities is as follows:

- The facilities adopted for Study purposes are considered reasonable but do not arise from detailed investigation of the alternatives, which may suggest a preference for different options.
- Topsides weight of the FPP's should be minimized.
- FPP hull configuration should be optimized against the specific environmental characteristics of the Hibernia location with respect to:
    - long term structural integrity (say, in excess of 30 years life);
    - motion response;
    - intact and damaged stability.

- Topsides facilities design criteria require consistent definition as a result of:
  - detailed reservoir analysis;
  - consideration of onshore gas utilization.
- Considerable process computer simulation/optimization is required to establish the preferred design approach.
- An integrated systems design approach to subsea equipment is essential but the lead time on CMC's significantly influences the pre-drilling programme.
- The extent of protection required to avoid damage from iceberg scour for subsea equipment and flowline/transfer lines requires detailed investigation.
- Design of the riser will be the key factor with regard to the availability of the FPP to continue production in severe weather conditions.
- The characteristics of the crude oil storage/mooring/loading system should be determined from operational simulation of the development.

It is emphasized that, with regard to all components of the development and their integration, the inherent safety of the facilities built into the design, and the safety systems and their associated operation procedures, will be of paramount importance.

1.6 GAS AVAILABILITY - SUMMARY

1.6.1 Basis for Gas Availability

Consideration of gas transmission system requirements has been based on the given Study premise of an average assumed daily production of 250 MMSCFD from the Field after off-take for fuel gas.

Such quantities should not be assumed definitely available for export either in whole or in part since gas may be required for reservoir pressure maintenance purposes. Further, the potential for gas export may not arise for a number of years following first oil production.

1.6.2 FPF Gas Usage Requirements

The offshore gas usage requirements of the individual production centres is estimated to be as follows, given the throughputs assumed and the functional distribution of facilities between centres as adopted:

Production Centre		Average Fuel Gas Demand in the Peak Year of Production
Avalon North		12.0 - 14.5 MMSCFD
Avalon South		12.9 - 15.6 MMSCFD
Hibernia North		4.4 - 5.2 MMSCFD
Hibernia South	- Gas Injection Mode	16.7 - 20.4 MMSCFD
	(Gas Export Mode)	(11.0 - 13.4 MMSCFD)
FIELD TOTAL	- Gas Injection Mode	46.0 - 55.7 MMSCFD
	(Gas Export Mode)	(40.3 - 48.7 MMSCFD)

Possible fuel gas deficiency at particular centres should receive careful consideration, particularly for Avalon North where associated gas production is lowest.

1.6.3 Overall System Operational Efficiency

An assessment of order-of-magnitude operational efficiency of the system indicates the following possible contributory factors:

	Factor	Effect and Annual Allowance
1.	Well Performance and Maintenance	5% to 10% reduction in peak oil availability for a given number of wells.
2.	Subsea Equipment	10% to 20% overall downtime due to complexity of system but effective design may reduce this to, say, 5%.
3.	Weather Downtime	
	* Floating Production Platforms	15% to 20%, possibly greater, depending on FPP motion characteristics and riser operational design criteria.
	* Oil Storage/Mooring/ Loading System	10% to 15% with, say, seven days storage to be confirmed by operational simulation.

	Factor	Effect and Annual Allowance
4.	Topside Facilities	
	* Oil/Gas Separation Plant	90% to 95% uptime between shutdowns for other reasons.
	* Gas Injection/Export Plant	92% to 96% uptime between shutdowns of the oil/gas separation plant.
5.	Gas Transmission System	Better than 98% uptime between shutdowns of the offshore plant.

The above excludes the effects of major failure, all allowances requiring confirmation by detailed operational analysis.

The above events are not additive but must be combined statistically. For Study purposes it is assumed that systems can be designed such that the integration of all factors may result in an overall annual efficiency of 75% to 80%, subject to detailed analysis of specific systems.

Further factors which may influence production are the specification by regulatory authorities of maximum allowable off-take from the reservoir during a particular period, e.g., per stream day, per calendar month, quarter or year, and any regulatory limitations on flaring.

Day-to-day fluctuations in production rates and flaring levels are inevitable and it is essential that the operator and the regulatory authority establish a clear, common understanding of circumstances which lead to such fluctuations and that off-take levels include some flexibility in this respect. The common goal should be measured by the long term average production rate from the Field, preferably the annual average target.

1.6.4 Gas Quantities Potentially Available for Export

If a full allowance is made for an overall annual operating efficiency of 75% to 80%, average stream day production rates of 350,000 BOPD to 373,000 BOPD would be required based on the annual average oil production of 280,000 BOPD. Corresponding separator off-gas rates may be in the order of 370 MMSCFD to 408 MMSCFD resulting in an average stream day availability of gas for potential export in the order of 330 MMSCFD to 360 MMSCFD after fuel gas off-take. These rates do not account for peak stream day rates which may be higher. The capability of the reservoir to support such production levels cannot be defined at this time.

Also the design capacity of the process facilities may be up to 100% above the average annual rate depending on operator preference.

The basis for the topsides equipment weight and costs developed in the Study is the given annual average oil and gas production rates of 280,000 BOPD and 250 MMSCFD respectively. Adequate margins are included to meet the given average stream day requirement of 320,000 BOPD. Average stream day oil rates in the order of 350,000 BOPD to 373,000 BOPD cannot be considered achievable within included equipment margins. A re-assessment of weight and space requirements will need to be undertaken when required peak stream day off-take has been defined as a result of detailed reservoir analysis and operational simulation of the Field to establish the overall level of operational efficiency.

The capacity of 24" gas pipeline adopted for Study purposes is 430 MMSCFD of "dense phase", "rich" gas, given the assumed operating conditions, and thus has an adequate margin to meet the high average stream day gas rates indicated above.

1.7 GAS TRANSMISSION SYSTEM - SUMMARY

1.7.1 Pipeline Termination and Routing

It is emphasized that the scope of the Study excludes the question of deep burial of the submarine gas pipeline to reduce the risk of damage due to iceberg scour, particularly in the hard rocks of the Avalon Channel, since it is recognized that there is no feasible method for trenching in rock which is acceptable for extensive lengths of exposed line in deep water.

Insufficient data is available on the engineering properties of surficial sediments and underlying "bedrock" along any potential route to enable a preferred route to be selected at this time, from a trenching point of view.

Trenching by conventional means, e.g., jetting or mechanical cutter, may be feasible and acceptable in the semi-consolidated Cretaceous-Tertiary "bedrock" which arises to the south of latitude 46°15'N. For this reason only southerly routes are considered in order to maximize the potential for burial but recognizing the fact that an exposed line on a shallower water depth southerly route may be at greater risk than a deeper water depth northerly route.

Long Harbour, Placentia Bay is adopted as a reasonable termination point for the gas line since this is a designated development area.

With respect to pipeline routing, the main Study emphasis is placed on a 260 mile submarine gas pipeline from Hibernia to Trepassey Bay with a 70 mile landline to Long Harbour. Subsequent to completion of the main Study, brief consideration has been given to a shorter, northern route comprising a 195 mile offshore pipeline from Hibernia to Bay Bulls with a 55 mile landline to Long Harbour.

An alternative wholly offshore route to Long Harbour, 360 miles long, was briefly reviewed but rejected due to increased cost, although such a route may permit conventional burial through the Avalon Channel.

1.7.2 Alternative System Arrangements

For the adopted route, the simplest arrangement was adopted, i.e., no intermediate compression or reduction in specification of the landline compared to the sealine. Detailed study would be required to confirm this arrangement.

The pipeline system is thus an integral design through the landfall with minimum equipment requirements at the landfall. The inclusion of offshore intermediate compression in the system is not expected to be economic due to cost but possible compression or pressure regulation at the landfall in order to reduce the requirement for heavy wall pipe in the landline should be investigated during basic engineering.

The gas reception facilities at Long Harbour are considered to be minimal, i.e., slug catcher, pig/sphere receiver, etc., since gas processing facilities are not included in the scope of work and since onshore utilization of the gas is not defined at this time.

Multiple pipeline systems of similar capacity to a single line are not considered at this time to offer any particular cost effective benefits as regards improved security of supply, compared to the single line approach over the distances involved, assuming that the single line is laid over the route offering the most advantageous natural seabed protection. This preliminary conclusion should be reviewed as more definitive risk data concerning iceberg scour emerges. In particular, twinning of the main gas pipeline over relatively short but particularly exposed distances may be considered. Flexible or reel barge laid pipes are not considered practical for this application due to the large diameter line and the long length of the route.

1.7.3 Conceptual System Configuration and Specification

The gas transmission system adopted transmits a "rich" condensing gas in the "dense phase" at high operating pressure. Inlet pressure is assumed to be 2,700 psig with the outlet pressure in the "just pigged" liquid-free condition being 1,500 psig. As liquids drop-out in the line the outlet pressure declines and when 1,200 psig is approached the line would again be pigged/sphered to displace liquids.

A 24" O.D. line diameter is adopted for the 330 mile southern route having a capacity of 430 MMSCFD of "dense phase" gas, given the above operating conditions. A reduction in line size, to say 22", for the shorter northern route, compared to the southern route, is considered a possibility, subject to detailed engineering. 22" line pipe is non-standard however and a cost premium may apply. For the purposes of this Study, therefore, a 24" is also adopted for the 250 mile northern route having a capacity of 500 MMSCFD of "dense phase" gas.

A summary of the submarine pipeline preliminary specification is as follows:

Diameter : 24" O.D.
Material : API 5LX60
Wall Thickness : 0.75"
Concrete Weight Coat : 2" to 2-1/2", thickness increase as required for stability or protection
Corrosion Protection
  - External : Coal tar wrapping with "thin film" epoxy near Hibernia South; Sacrificial Anodes
  - Internal : Gas dehydration
Valves/Fittings : ANSI 1500

The landline would be of similar material without the concrete weight coat and with "thin film" powder epoxy coatings throughout for corrosion protection.

1.7.4 Design and Engineering

Design and engineering of the system would be conventional. With the exception of deep burial of the submarine line for iceberg scour protection, no particular problems are envisaged, although additional protective measures, e.g., anchor blocks, may be required for exposed lengths of the pipe.

Considerable survey data is required for alternative routes with respect to both environmental and physical characteristics.

Any relevant Canadian Federal and Provincial Government Acts of Parliament and Statutory Regulations would be adhered to.

1.7.5 Construction and Installation

The material requirements for line pipe, coatings, etc., are not exceptional within the offshore industry although it is noted that at this time Canadian mills cannot supply 24", API 5LX60, 0.75" wall thickness pipe.

Pipe coating would preferably be carried out at a suitable site in Newfoundland to reduce transportation costs and difficulties.

The water depths and environmental conditions for laying the submarine pipeline over the route considered are within industry capabilities. The landline construction will be expensive due to the possible extent of rock ditching and grading required but is not exceptional as regards industry capability.

Due to the severe weather conditions anticipated offshore, a third generation semi-submersible laybarge has to be assumed for pipeline construction but final selection of barge type will be the result of detailed technical and economic comparison of available barges, preferably involving simulation of the laying operation.

A five to seven month "weather window" for offshore construction is considered reasonable at this time, say, April/May through September/ October.

Should underwater trenching with available equipment prove possible in the soils along the route, a depth of cover of three feet is conventional but this does not provide significant protection from potential iceberg scouring. Unless required by regulations, trenching may not be necessary for on-bottom pipe stability and is not considered to provide any significant additional protection from trawl boards or small anchors unless natural backfill of the trench is effective. Suitable design of the concrete weight coat is normally adequate for such risks, trenching and burial providing little protection from large anchors.

1.7.6 Operations, Maintenance and Repair

The operations and maintenance requirements of a submarine pipeline and landline are few and not complex. Regular survey and inspection would be undertaken to maintain the pressure integrity of the line with remedial work being carried out as required.

Repair of the submarine pipeline does not present any particular difficulties in the water depths envisaged, permanent repairs probably being achieved by spool piece insertion and underwater, dry, hyperbaric welding.

The critical aspect of such repairs is that any occurrence during severe weather may require several months to complete and prove expensive. Detailed evaluation of the risk of rupture due to iceberg scour is required to enable an economic assessment to be made of the impact of repair cost on the Field operating cycle.

Repair of the landline will not present any particular difficulties.

In operation, the pipeline will need to be pigged/sphered to remove liquids. Since it is unlikely that pigs/spheres will be able to be launched from the FPP deck, a subsea launching system may be required.

1.7.7 Associated FPP Systems and Equipment Requirements

Given the development concept as adopted, and the transmission of "dense phase", "rich" gas, the significant additional FPP equipment requirements offshore compared to those required for gas injection are as follows:

- Gas dehydration
- Metering for sales and fiscal purposes
- Pig/sphere launching
- Instrumentation and Control
- Telecommunications

Gas export would utilize the first stage of the two-stage gas injection compression system and hydrocarbon dewpoint control is only required if a higher quality gas is exported.

The additional FPP requirements for gas export are, therefore, minimal and will have little effect on the development concept as adopted for Study purposes.

1.7.8 System Flexibility with Respect to Additional Gas Quantities

The "dense phase" capacity of the southern, 330 mile, 24" pipeline system represents a margin of 72% over the average annual throughput of 250 MMSCFD, while the corresponding margin for the northern, 250 mile pipeline is 100%. While sufficient to handle peak loads from Hibernia, these margins are not considered adequate to accept incoming gas from other fields unless Hibernia gas production is deferred. The acceptability of such deferment depends on its duration and quantity.

Typical line sizes capable of transmitting additional quantities of "dense phase" gas may be as follows (assuming the same inlet/outlet conditions as previously, i.e., 2,700/1,500 psig):

Line Size	Peak Throughput (MMSCFD)	
	330 Miles	250 Miles
28"	650	750
30"	780	890
32"	930	1,070

Significant additional gas quantities may therefore be transmitted with relatively small increases in pipeline diameter.

Any additional gas should be treated to "Hibernia" quality elsewhere and should arrive at the Hibernia South Riser Manifold base (or a "Tee" piece downstream) at a suitable inlet pressure. Any other arrangement will require significant modifications to the Hibernia South Riser and Topside Facilities, particularly if gas treatment is required. However, should a separate (fifth) platform be available at Hibernia, e.g., for water and gas injection, then such treatment and any additional compression required may possibly be incorporated.

1.7.9 Critical Areas of the Gas Transmission System

The principal critical areas associated with the gas transmission system as adopted for Study purposes are as follows:

- The unresolved risk of rupture of the main submarine gas pipeline as a result of iceberg scour and which requires:
  - improved statistical evaluation of such risk;
  - improved knowledge of the Cretaceous-Tertiary soils along the southern route to assess trenching potential;
  - definition of an acceptable level of risk in technical and economic terms;
- definition of the landed gas specification;
- detailed comparison of alternative pipeline destinations, landfall and routes;
- definition of average and peak throughputs and possible variation during the life of the system;
- collection, correlation and formatting of environmental and seabed soils data for use in selecting the preferred route and arrangement;
- detailed evaluation of the interface of the pipeline with the FPP production deck particularly with respect to pig/sphere launching.

In summary, the integration of gas transmission facilities with the Floating Production Facilities is considered technically feasible although engineering development of the FPP/pipeline interface is required. Since rupture of the submarine gas pipeline is not a considerable environmental risk, the acceptability of the gas transmission may depend ultimately on development economics and regulatory approval.

1.8 DEVELOPMENT PLAN/SCHEDULE - SUMMARY

1.8.1 Basis for the Development Plan

The objective in considering an overall Field development plan for Study purposes is to determine whether the gas transmission system is a critical area from a project scheduling aspect.

The overall schedule is divided into two main phases; the pre-project and the project phase. An outline of the pre-project phase is included for information only, since:

i) The status of the operator's preliminary studies, particularly reservoir definition and development plan, is not well defined at this time.
ii) The date of submission for approval of the Hibernia Field Development Plan is not known.
iii) The possible duration of the approval procedure cannot be predicted at this time.

Considerable systems design and basic engineering is likely to be required prior to commitment to major design and construction contracts in order to ensure an integrated approach to the project phase.

The project phase schedule includes the key programme areas for each item, i.e.:

* detailed design
* construction/fabrication bid cycle
* procurement/delivery
* onshore construction/fabrication
* offshore construction/installation and commissioning

A basic six month "weather window" for offshore activities has been assumed, May to October.

To the maximum extent possible, and particularly for the Floating Production Platforms, offshore construction is minimized and equipment pre-commissioned onshore or at the dockside prior to installation of the complete FPP offshore.

A large, third generation semi-submersible laybarge has been assumed for laying the 24" main submarine gas line to minimize downtime due to weather. Final selection of laybarge type will depend on operational simulation, economics and laybarge availability.

An allowance is included for "conventional" trenching over 200 miles of the 260 mile southern offshore route and 50% (97.5 miles) of the northern offshore route but the feasibility of this has yet to be established by detailed study.

1.8.2 Overall Conceptual Field Development Plan/Schedule

A representative plan/schedule has been devised relating to the Field Development Concept adopted for Study purposes.

The overall duration is relatively long, time to first oil being in the order of six years after commencement of the project phase with first gas available in the next project year. This assumes complete, integrated development of the whole Field with no "phased" development of the reservoir.

The extensive duration is significantly influenced by the assumption that major seabed excavations, or "glory holes", are required to provide subsea equipment with protection from iceberg scour and that excavation is undertaken by a clamshell dredge system. Should the requirements or methods adopted for scour protection change as a result of detailed investigation, the overall schedule may possibly be compressed by, say, 12 months. The overall duration is also influenced by the need to complete a certain amount of pre-drilling prior to commencement of production.

Within the apparent "critical" path indicated by the above the construction/fabrication of other key components of the development, e.g., the FPP's, is scheduled making use of available time. Detailed planning may reduce the schedules indicated for individual components.

It is assumed that the two Avalon FPP's would be installed in one season with the two Hibernia FPP's in the next season. This permits reasonable scheduling of construction and reduces the intensiveness of the subsea equipment installation schedule.

It is considered that phased development of the Hibernia Field may offer benefits in terms of improving reservoir knowledge, gaining production experience and providing lead time for the consideration of alternative development concepts and onshore utilization of gas. The Hibernia sand zone may constitute a second phase of development with the Avalon zone being exploited initially.

1.8.3 Gas Transmission System Schedule

Within the overall development plan as devised, the construction of the gas transmission system is not considered a critical activity.

Offshore construction of the submarine gas pipeline for either the southern or northern route requires two laying seasons, construction of the landline also being spread over two seasons.

Considerable pre-lay route surveying and preparation is required. A post-lay survey will determine the as-laid condition of the line and as a result an undefined amount of remedial work may be required, e.g., for the submarine line, to reduce free spans, repair damaged weight coat, etc.

The gas reception facilities, which comprise no gas processing/treatment equipment, may require a minimum construction programme of 15 months.

1.8.4 Critical Areas of the Development Plan

Critical areas of the development plan are as follows:

- * The conceptual development plan as devised does not necessarily show minimum construction/supply times and detailed planning may result in a compression of the overall schedule, subject to "glory hole" excavation and pre-drilling requirements.
- * The influence of maximizing Newfoundland or Canadian content has not been considered and its possible effect on scheduling should be the subject of detailed study.
- * The selection of construction sites and laybarge type must be carried out early in order to reserve construction yard and laybarge capacity.
- * The date of commencement of the project phase is undefined at this time, the overall duration of the project depending on the development concept eventually selected.
- * A requirement for deep burial of the main submarine gas pipeline in difficult soils, and/or alternative means of protection if necessary, will considerably extend the pipeline construction schedule. Extensive trenching through the hard rock of the Avalon Channel is not considered feasible at this time and is not included in the schedule.

Phased development of the Field should be investigated and would considerably modify and lengthen the schedule.

1.9 CAPITAL AND OPERATING COST ASSESSMENT - SUMMARY

1.9.1 Basis for Cost Assessment

The datum for cost assessment is 1st January, 1982.

Costs have been substantially based on North Sea project costs since it is assumed that, in general, market forces will tend to determine the supply of materials, equipment and services. In this respect, Newfoundland or Canadian sourced items may not differ considerably in base cost terms compared to international supply, which is in itself variable depending on actual source. "Canadianization" may have an implicit cost impact, however, e.g., where a new facility is constructed and a "learning curve" applies.

The following aspects are excluded from the assessment:

- Pre-Project Costs
- Development Drilling
- Taxation and Inflation

Contingency allowances are made for lack of project definition at this time, estimating short falls, items omitted and reasonable unscheduled delays and downtime.

The assessment of Floating Production Facilities and the Gas Transmission System is based on a set of key rates for services compiled for Study purposes. Such rates are considered representative at this time but considerable variation may arise depending on the point in time the services are contracted and the availability of such services.

1.9.2 Overall Project Costs

The overall project budget costs including a southern pipeline route via Trepassey Bay are summarized as follows:

OVERALL PROJECT BUDGET COSTS - INCLUDING SOUTHERN ROUTE

	Cost, $MM, 1st January, 1982		
Project Area	Base Cost	Contingency	Total
A. Offshore Structures and Facilities	3,170.68	951.20	4,121.88
B. Submarine Gas Pipeline	618.22	123.64	741.86
C. Onshore Gas Landline	150.78	15.08	165.86
D. Onshore Gas Reception Facilities	23.80	4.76	28.56
PROJECT TOTAL	3,963.48	1,094.68	5,058.16

The overall project budget costs including a northern pipeline route via Bay Bulls are summarized as follows:

OVERALL PROJECT BUDGET COSTS - INCLUDNG NORTHERN ROUTE

	Cost, $MM, 1st January, 1982		
Project Area	Base Cost	Contingency	Total
A. Offshore Structures and Facilities	3,170.68	951.20	4,121.88
B. Submarine Gas Pipeline	499.09	99.82	598.91
C. Onshore Gas Landline	114.93	11.49	126.42
D. Onshore Gas Reception Facilities	23.80	4.76	28.56
PROJECT TOTAL	3,808.50	1,067.27	4,875.77

Due to the extensive subsea production systems involved and the requirement for four Floating Production Platforms, a high level of contingency has been applied for lack of definition at this time, amounting to approximately 28% of the Base Project Cost for both the southern and northern systems.

On the assumption that pre-project costs may be in the order of $400 MM to $500 MM, and that development drilling may cost in the order of $2,000 MM (based on 88 wells excluding wellhead/completion equipment which is included in the Base Cost) the total Hibernia Project may cost in the order of $7.51 Billion in 1.1.1982 terms including the southern Trepassey Bay Pipeline Route. The corresponding cost including the northern Bay Bulls pipeline route is in the order of $7.33 Billion in 1.1.82 terms.

Due to the extensive development schedule, inflation on 1.1.1982 costs may be substantial.

It is emphasized that the above costs are based only on the development concept adopted for Study purposes. The engineering approach finally selected by the operator may result in significant variations compared to the costs developed in this preliminary investigation.

Operating costs for the development including either a southern or northern pipeline system have been based on a percentage of total capital expenditures and for the year of peak production are estimated as follows:

Project Area	Peak Year Operating Cost $MM p.a., 1.1.82	
	Southern	Northern
A. Offshore Structures and Facilities	309.14	309.14
B. Submarine Gas Pipeline	37.09	29.95
C. Onshore Gas Landline	1.66	1.26
D. Onshore Gas Reception Facilities	0.86	0.86
PROJECT TOTAL	348.75	341.21

The above does not include the cost of well workovers and maintenance or for crude oil transportation. Running costs per well may be in the order of $300,000 pa. with a major workover being required on each well approximately every three years costing in the order of $3 MM per well. For a 1,000 mile voyage radius, tanker transportation tariffs may be in the range of $1 to $2 per barrel.

1.9.3 Gas Transmission System Costs

The overall pipeline costs for the southern route are assumed as follows:

	Cost, $MM, 1st January, 1982		
System Area	Base Cost	Contingency	Total
Submarine Gas Pipeline	618.22	123.64	741.86
Onshore Gas Landline	150.78	15.08	165.86
Onshore Gas Reception Facilities	23.80	4.76	28.56
SYSTEM TOTAL	792.80	143.48	936.28

The overall pipeline costs for the northern route are assumed as follows:

	Cost, $MM, 1st January, 1982		
System Area	Base Cost	Contingency	Total
Submarine Gas Pipeline	499.09	99.82	598.91
Onshore Gas Landline	114.93	11.49	126.42
Onshore Gas Reception Facilities	23.80	4.76	28.56
SYSTEM TOTAL	637.82	116.07	753.89

Operating costs for the system in the year of peak production amount to 39.61 MM p.a. and $32.07 MM p.a. for the southern and northern routes respectively.

The cost of offshore equipment at Hibernia South which is specifically associated with the gas transmission system, including:

* gas dehydration/regeneration unit
* gas metering
* pig/sphere launching and additional piping, instrumentation, bulks, etc.
* a factored portion of the riser and Riser Manifold Base

is estimated at a total capital cost of $12.46 MM with a peak year operating cost of $0.94 MM p.a.

The overall gas transmission system costs in 1.1.1982 terms, including contingency, are therefore estimated to be as follows:

	Southern Route	Northern Route
Project Budget	$948.74 MM	$766.35 MM
Peak Year Operating Cost	$ 40.55 MM p.a.	$ 33.01 MM p.a.

The operating costs for the pipeline exclude major repair due to pipeline rupture which may cost in the order of $5 MM to $25 MM depending on severity of the damage.

With respect to improving security of supply, given the risk of iceberg scour damage to the submarine pipeline, multiple pipelines over the entire offshore length with combined throughputs equivalent to the single line are a high cost option incurring at least 50% or 100% increase in cost (for double or triple lines respectively) compared to the single line. Twinning the line over relatively short, particularly exposed distances is also high cost, but may warrant consideration if the risk is high.

The installation of an over-size submarine pipeline capable of handling additional quantities of gas, either from Hibernia or elsewhere, should be considered if the probability of additional gas is high, since the multiplier on cost is significantly less than the multiplier on throughput. For example, over the southern route, a 32" pipe offers a 2.16 increase in peak throughput compared to the 24" pipe, the corresponding cost increase being estimated as 35% to 40%.

For the northern route, should detailed engineering and supply negotiations result in the recommendation of a 22" line, rather than a 24", then capital costs may be reduced by approximately $40 MM, as long as no premiums are applied for the supply and construction of a non-standard line.

1.9.4 Capital Expenditure Phasing

A summary of the capital expenditure phasing of each key area of the project is given in Tables 1-1 and 1-2 for total field development including either a southern or a northern pipeline system.

The indicated phasing should be regarded as preliminary and indicative only and may vary considerably for a different development concept and with detailed technical definition and planning.

1.9.5 Critical Areas of the Cost Assessment

Significant variation in costs may arise if a different development concept is adopted compared to that devised for Study purposes. Given the technical definition and development schedule for the concept described herein, the following areas are critical to the cost assessment:

TABLE 1-1 PROJECT CAPITAL EXPENDITURE PHASING

(INCLUDING SOUTHERN PIPELINE VIA TREPASSEY BAY)

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

PROJECT AREA	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. OFFSHORE STRUCTURES AND FACILITIES	4,121.88	39.00	311.38	782.82	1,264.25	1,117.41	500.11	104.43	2.48
2. SUBMARINE GAS PIPELINE	741.86	6.85	96.72	280.49	209.52	78.46	56.30	13.52	-
3. ONSHORE GAS LANDLINE	165.86	0.66	2.20	65.73	43.80	52.92	-	0.55	-
4. ONSHORE GAS RECEPTION FACILITIES	28.56	-	-	1.82	18.58	6.84	-	1.32	-
TOTAL PROJECT BUDGET	5,058.16	46.51	410.30	1,130.86	1,536.15	1,255.63	556.41	119.82	2.48

NOTES: 1. Project Budget Excludes Pre-Project Costs And Development Drilling Costs.

2. All Costs Are Based 1.1.82 With No Allowance For The Effects Of Inflation.

3. Construction Of The Landline And/Or Gas Reception Facilities May Be Delayed By One Year If Desired.

TABLE 1-2 PROJECT CAPITAL EXPENDITURE PHASING

(INCLUDING NORTHERN PIPELINE VIA BAY BULLS)

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

PROJECT AREA	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. OFFSHORE STRUCTURES AND FACILITIES	4,121.88	39.00	311.38	782.82	1,264.25	1,117.41	500.11	104.43	2.48
2. SUBMARINE GAS PIPELINE	598.91	5.86	80.32	221.81	164.02	105.49	9.41	12.00	-
3. ONSHORE GAS LANDLINE	126.42	0.51	1.69	51.29	33.95	38.58	-	0.42	-
4. ONSHORE GAS RECEPTION FACILITIES	28.56	-	-	1.82	18.58	6.84	-	1.32	-
TOTAL PROJECT BUDGET	4,875.77	45.37	393.37	1,057.74	1,480.80	1,268.32	509.52	118.17	2.48

NOTES:
1. Project Budget Excludes Pre-Project Costs And Development Drilling Costs.
2. All Costs Are Based 1.1.82 With No Allowance For The Effects Of Inflation.
3. Construction Of The Landline And/Or Gas Reception Facilities May Be Delayed By One Year If Desired.

- Detailed technical definition is required to confirm the cost assessment which is considered representative but order-of-magnitude only.
- Contingencies, project design, management, etc., are all applied on a global basis and should, with increased definition, be associated with each individual item.
- Inflation, taxation, the point in time when services are acquired and contracts let, the source of supply and location of construction/fabrication sites will have a significant effect on the costs.
- The extent and method of protecting subsea equipment from iceberg scour is a high cost item and warrants detailed investigation of alternatives.
- The allowance included for trenching of the submarine gas pipeline is nominal only and may increase considerably if soil conditions are difficult or if alternative means of protection are required for untrenched lengths of line.
- The cost of the landline is high and may vary depending on the extent of difficult laying conditions, especially rock ditching, over the route selected.
- The inclusion of gas processing/treatment facilities at the gas reception terminal would significantly increase costs.
- Phasing of the development would significantly alter the cost assessment.

In overall terms, the addition of a gas transmission system adds considerably to the costs of the Hibernia project, its inclusion depending on economics and the acceptability of the risk of iceberg scour damage.

SECTION 2

STUDY PREMISES AND APPROACH

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2.0 STUDY PREMISES AND APPROACH

2.1 STUDY PREMISES

At commencement of the Study and during the course of the work, a number of significant premises were established upon which the Study is based. These premises are summarized below.

2.1.1 Overall Field Development Concept

i) The overall concept involves Floating Production Facilities (but is not intended to indicate any preference for such facilities nor exclude alternative concepts, e.g., fixed platforms, from further consideration outside this Study).

ii) Four separate production centres are assumed with designated production rates given as input data to the Study (refer to Section 3.1.2).

iii) Onshore utilization of landed Hibernia gas is not defined at this time (with the implication that transmission of "dense phase", "rich" gas may be acceptable, such gas requiring significant processing onshore as opposed to offshore).

iv) Gas production and transmission is assumed to be an integrated part of the Hibernia Field development plan (and not simply an "add on" to oil production facilities).

v) A reasonable Field development concept is adopted for Study purposes, but is not based on detailed investigation, comparison and evaluation of alternatives, the adopted concept not indicating any preference for the overall arrangement or individual components utilized.

vi) The entire Hibernia Field is assumed to be developed in a single project without any consideration of phased development of the resource.

2.1.2 Production and Export Systems Design Philosophy

i) The facilities are to produce stabilized crude oil of suitable vapour pressure for export by offshore loading of shuttle tankers and to produce gas suitable either for re-injection to the reservoir or for potential export at some undefined future point in time.

ii) Considerable water injection capacity is required (refer to Section 4.1.2).

iii) Provision is to be made for the disposal of produced water (refer to Section 4.1.2).

iv) The specification or quality of landed gas is not defined at this time.

2.1.3 Floating Production Facilities

i) Semi-submersible floating production platforms (FPP's) of conventional configuration (i.e., similar to existing exploration semi-submersible rigs) may be adopted if considered appropriate.

2.1.4 Gas Availability

i) The annual average oil production rate is 280,000 BOPD. The corresponding annual average gas production rate of 250 MMSCFD is assumed to be available for re-injection or potentially for export, fuel gas usage being additional to the 250 MMSCFD.

ii) Average stream day gas production will be 14% greater than the above in accordance with a peak oil offtake level of 320,000 BOPD.

iii) Gas may initially be required for reservoir pressure maintenance. Gas may not be available for export until some years after oil production commences.

iv) The effect of additional quantities of gas becoming available from outside the Hibernia Field is to be considered.

2.1.5 Gas Transmission System

i) The destination of the gas, for Study purposes, is assumed to be Long Harbour, Placentia Bay (this being assumed as a reasonable destination since Long Harbour is a designated industrial development zone, but without prejudice to the actual destination which may arise).

ii) A southerly route is assumed in order to maximize the potential for possible trenching of the submarine gas pipeline in the Cretaceous-Tertiary soils south of approximately latitude 46° 15' N.

Subsequent to completion of the main Study, brief consideration has been given to a direct, northern route via a Bay Bulls landfall.

Two alternative routes are considered; one making a landfall at Trepassey Bay with a landline to Long Harbour, the alternative being a submarine line directly to Long Harbour via Placentia Bay.

iii) Trenching of the submarine pipeline in the hard rocks of the main Avalon Channel is not considered feasible at this time. Any pipeline system evaluated at this time would be considered unburied/untrenched (other than for conventional purposes where assumed reasonable) until such time that more definitive pipeline route specific data becomes available.

iv) Assessment of the risk of damage due to iceberg scour, definition of acceptable risk and resolution of the general problem area is not within the scope of this preliminary investigation (as a result of (iii) above).

2.1.6 Development Plan/Schedule

i) Consideration of the overall Hibernia Field development plan/schedule is necessary in order to determine whether the gas transmission system construction is a critical activity within the overall schedule.

ii) The status of the operator's pre-project studies and field development planning is not well defined at this time. The date of submission for approval of the operator's development plan and the eventual duration of the approval process cannot be defined at this time (with the exception that the Petroleum Directorate's guideline document issued to the operator anticipates an eight-month duration between submission to cabinet decision).

iii) The Hibernia Field is considered as a complete integrated development with no phasing of the development.

2.1.7 Capital and Operating Cost Assessment

i) The datum for cost assessment is 1st January, 1982.

ii) The following costs are excluded from the assessment (but receive comment in this Report):

- Pre-Project Costs
- Development Drilling Costs
- Taxation

iii) The effects of inflation are not considered.

In addition to the foregoing premises under each heading, a number of assumptions have been made in order to progress the work. These assumptions are stated as arising in each Section of the Report.

2.2 STUDY APPROACH

The Study commenced on the 7th December, 1981 with an effective duration of three months.

Following a general "systems" approach, the Study proceeded in three phases as follows:

Phase I - Review and Overall Systems Configuration
Phase II - Systems Description and Gas Availability
Phase III - Cost Assessment and Reporting

The short time scale and overview nature of this preliminary investigation required that assumptions be made on total development concepts rather than a systematic combination of individual components of the development. Adoption of components or schemes for Study purposes was based substantially on engineering judgment rather than in-depth analysis.

Phase I commenced with a review of information and data available from the Petroleum Directorate and confirmation of the Study premises. This review included the physical and environmental characteristics of the Hibernia location and possible pipeline routes. The production rates upon which the Study is based were defined by the Petroleum Directorate. As a result of the review, the processing and operating philosophy for oil/gas production and gas transmission was developed and an overall development concept defined. The alternative pipeline routes were considered and one route adopted for Study purposes.

Phase II defined the overall Field development facilities, in order-of-magnitude terms, in sufficient depth to permit the development concept to be considered reasonable for Study purposes and in order that the development plan/schedule and overall development costs could be assessed. Gas availability was considered in terms of possible fuel gas usage and the influence of overall system efficiency. For the adopted pipeline route, a reasonable system arrangement was defined for Study purposes and a preliminary specification developed. The basis for programme and cost assessment was also developed.

Phase III involved the assessment of capital and operating costs for the overall development and for the gas transmission system and its associated equipment. The influence of additional quantities of gas becoming available from outside the Hibernia Field was considered. Preparation of the Final Report on the preliminary investigation was also carried out.

The Final Report was presented to the Petroleum Directorate on the 23rd March, 1982. Subsequent to the presentation of the final report on March 23, the Petroleum Directorate requested that information and considerations for a more direct Hibernia to Bay Bulls offshore pipeline route be included in the Study. The additional Study was completed during April, 1982.

SECTION 3

OVERALL FIELD DEVELOPMENT CONCEPT

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3.0 OVERALL FIELD DEVELOPMENT CONCEPT

3.1 RESERVOIR AND PRODUCTION CONSIDERATIONS

3.1.1 General

In considering the reservoir and production characteristics of the Hibernia Field, for Study purposes, the objectives are to establish the two key factors required for the conceptual design of the production and export systems, i.e.:

i) Peak Production Rates; and
ii) Indicative Hydrocarbon Fluid and Gas Analyses.

At present, following the P-15 discovery well in 1979, four delineation/appraisal wells have been drilled, O-35, B-08 and K-18 having been completed and tested; G-55A being dry. A sixth well, J-34, is now in progress. It is likely that several more appraisal wells will be required to improve knowledge of this complex field which has two main producing zones, defined as Hibernia and Avalon, with some indications of layering and both major and minor faulting to varying degrees in both zones, as well as a deeper horizon of low significance, the Jeanne D'Arc.

Current best estimates of the recoverable reserve potential of the Field, available to the Petroleum Directorate are:

Recoverable Oil : 1.9 Billion Barrels
Recoverable Solution Gas : 1.5 Trillion Cubic Feet
Recoverable Non-Associated Gas: 0.5 Trillion Cubic Feet

The location of the Hibernia Field is illustrated in Figure 3-1.

It is not within the scope of this preliminary investigation to carry out an evaluation of the reservoir and its production characteristics, such data being essentially provided by the Petroleum Directorate from knowledge of existing reservoir models available, together with the Directorate's prognosis of permissible offtake rates from the Field.

3.1.2 Production Rates

At an early stage in the Study, the basic premise that four separate production facility locations would be assumed was agreed, two serving the Hibernia zone and two the Avalon zone.

Average annual daily production rates for each production centre were given as input data to the Study as follows:

	Average Annual Daily Production Rates	
Production Facility	MBOPD	MMSCFD
Avalon North	50(60)	20
Avalon South	90(100)	30
Hibernia North	50(60)	100
Hibernia South	90(100)	100
	280(320)	250

Notes:
1. Data in parenthesis indicates given offtake per average stream day.
2. Gas production is assumed to arise after deductions for fuel gas usage.
3. The data assumed for Study purposes may not be representative of actual Field conditions (refer to Section 3.1.3) and production at each facility may be a combination of wells from both the Avalon and the Hibernia reservoir zones.

HIBERNIA FIELD DEVELOPMENT - LOCATION CHART

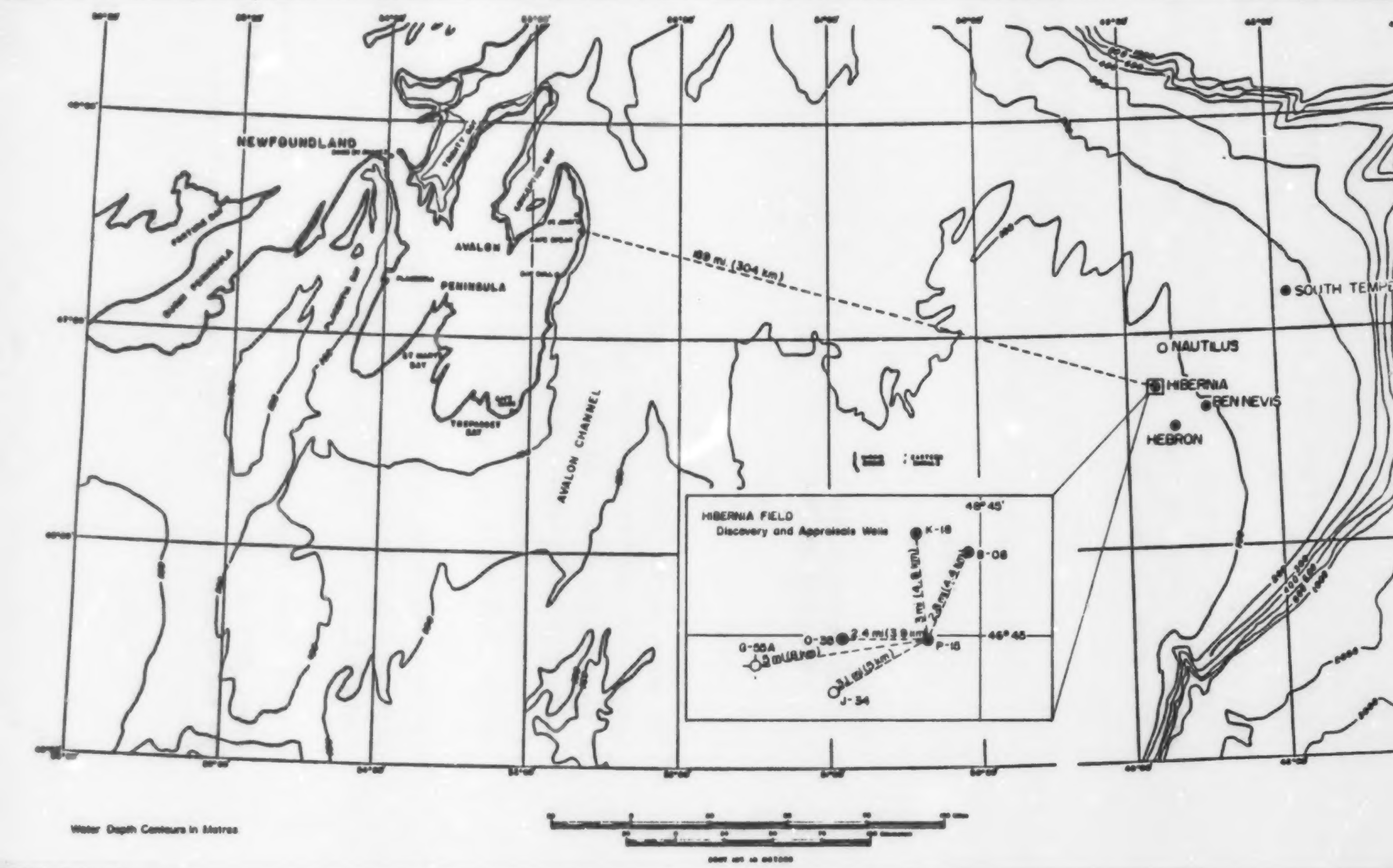

NEWFOUNDLAND
AVALON
PENINSULA
AVALON CHANNEL
189 mi (304 km)
SOUTH TEMPEST
NAUTILUS
HIBERNIA
BEN NEVIS
HEBRON
HIBERNIA FIELD
Discovery and Appraisals Wells
K-18
B-08
O-35
P-15
G-55A
J-34
48° 45'
46° 45
3 mi (4.8 km)
2.8 mi (4.5 km)
2.4 mi (3.9 km)
3.1 mi (5 km)
Water Depth Contours in Metres

Figure 3-1

The above rates are based on a reservoir interpretation by the Directorate of a median recovery rate for the most probable Avalon zone reserves and a maximum recovery rate for the most probable Hibernia zone reserves. The gas rates are assumed to arise after offtake for fuel and other gas uses. The corresponding number of wells given as input data to the Study is as follows:

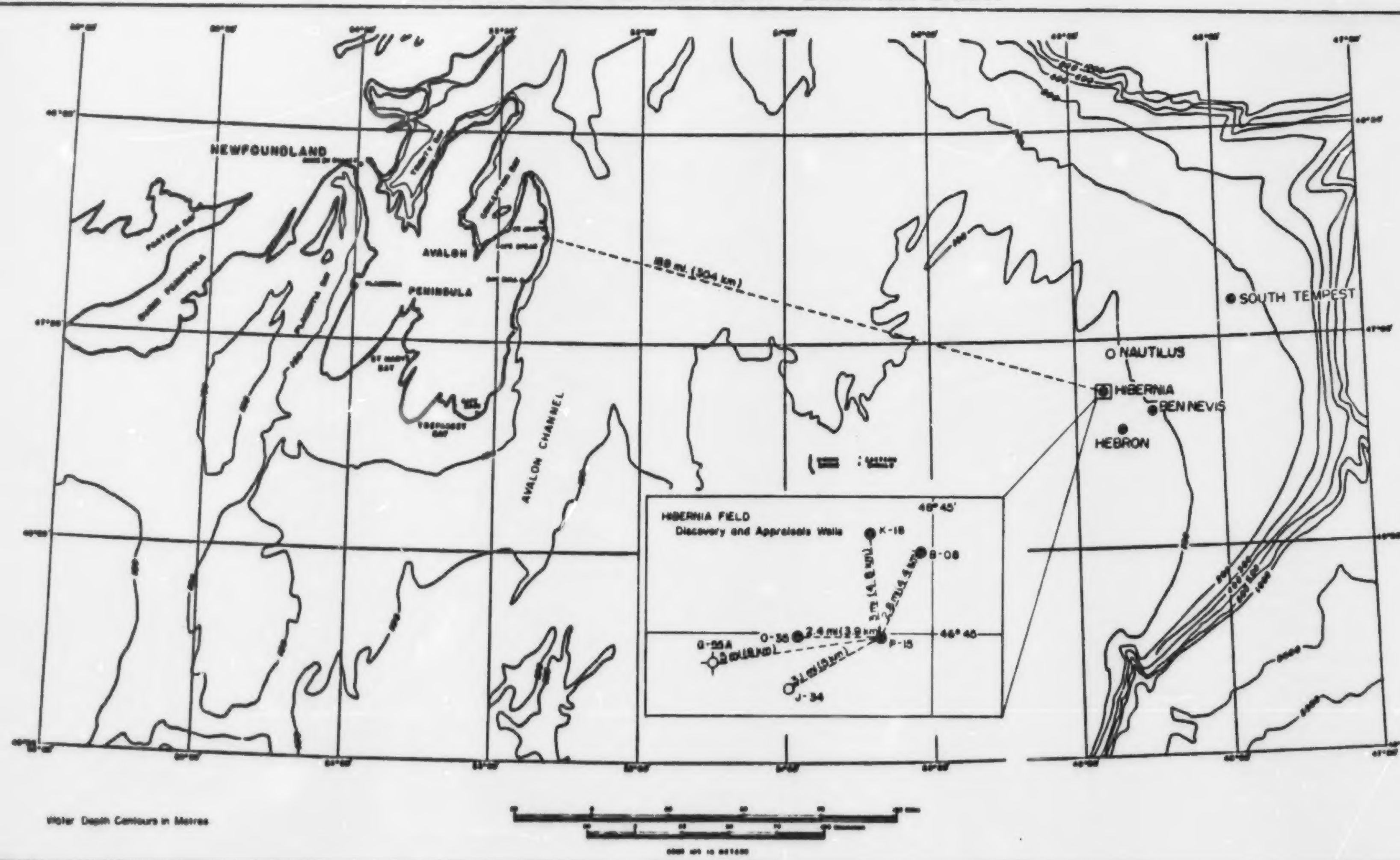
	Well Category			
Reservoir Zones	Production	Water Inj.	Gas Inj.	Total
Avalon North	6	2	-	8
Avalon South	11	5	1	17
	17	7	1	25
Hibernia North	5	1	1	7
Hibernia South	8	3	1	12
	13	4	2	19
TOTAL	30	11	3	44

The above production rates and numbers of wells give rise to some inconsistencies and anomalies concerning efficient and practical reservoir depletion, this being discussed in Section 3.1.3. The above data was, however, accepted as basic premises for the Study. A possible development plan, given as input data to the Study, based on the above number of wells is illustrated in Figure 3-2.

For information the Hibernia reservoir parameters derived from published test data on wells P-15, O-35, B-08 and K-18 are given in Table 3-1.

A total water injection requirement of 300,000 BWPD is given as input data to the Study. This level may be insufficient depending on the natural water drive and the injection efficiency.

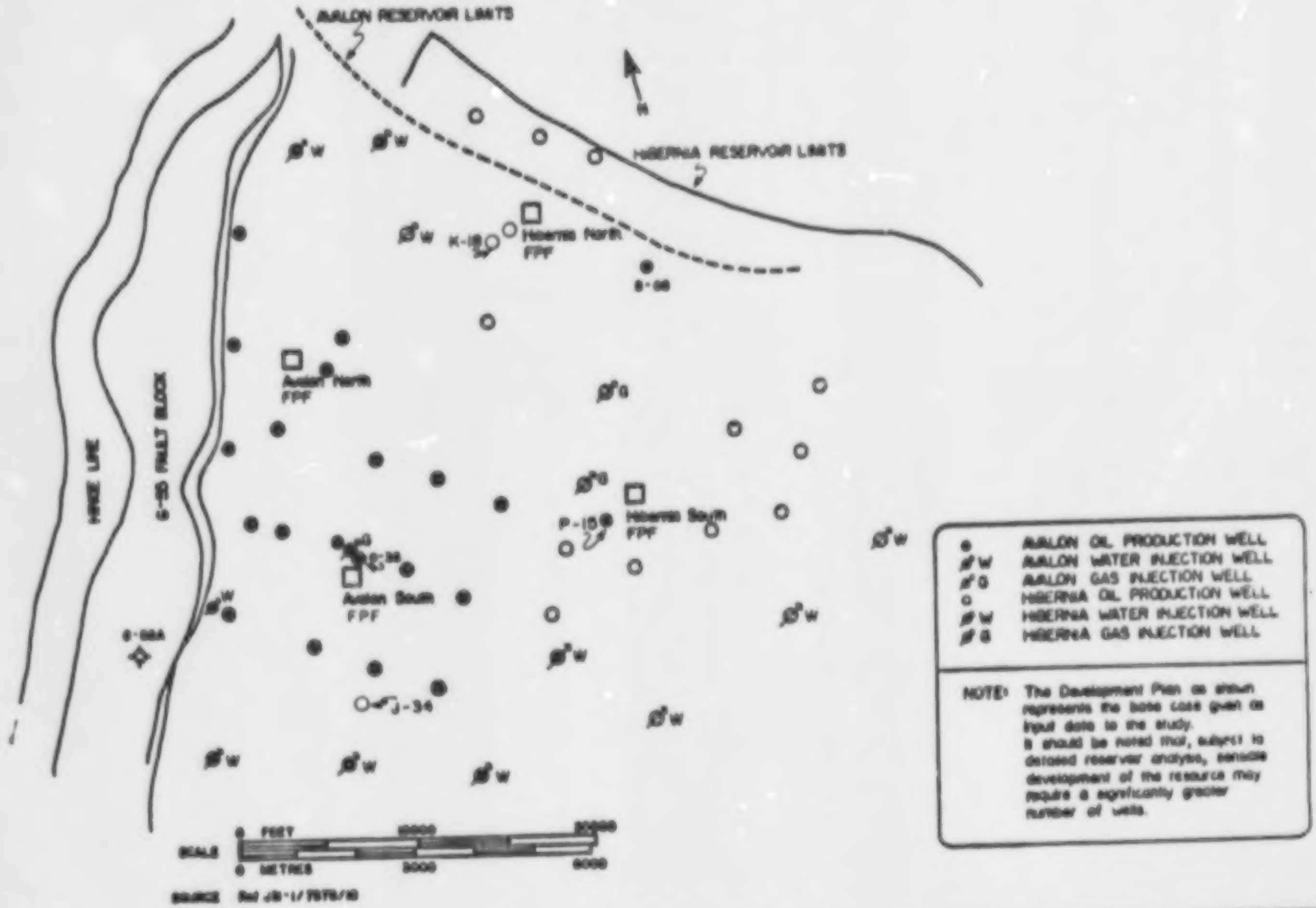
HIBERNIA FIELD DEVELOPMENT - LOCATION CHART


NEWFOUNDLAND
AVALON
PENINSULA
AVALON CHANNEL
188 mi (304 km)
SOUTH TEMPEST
NAUTILUS
HIBERNIA
BEN NEVIS
HEBRON
HIBERNIA FIELD
Discovery and Appraisals Wells
46° 45'
46° 40
K-18
B-08
P-15
O-35
G-55A
J-34
2.4 mi (3.9 km)
3 mi (4.8 km)
2.8 mi (4.4 km)
3 mi (4.8 km)
3.1 mi (5 km)
Water Depth Contours in Metres

575

Figure 3-1

POSSIBLE DEVELOPMENT PLAN FOR THE HIBERNIA FIELD-WELL TARGETS AND FPF LOCATIONS


AVALON RESERVOIR LIMITS
HIBERNIA RESERVOIR LIMITS
N
HINGE LINE
G-55 FAULT BLOCK
G-55A
K-18
Hibernia North FPF
B-08
Avalon North FPF
P-15
Hibernia South FPF
Avalon South FPF
J-34
● AVALON OIL PRODUCTION WELL
ø W AVALON WATER INJECTION WELL
ø G AVALON GAS INJECTION WELL
○ HIBERNIA OIL PRODUCTION WELL
ø W HIBERNIA WATER INJECTION WELL
ø G HIBERNIA GAS INJECTION WELL
SCALE
0 FEET 10000 20000
0 METRES 3000 6000
SOURCE

NOTE: The Development Plan as shown represents the base case given as input data to the study. It should be noted that, subject to detailed reservoir analysis, sensible development of the resource may require a significantly greater number of wells.

Figure 3-2

TABLE 3-1

HIBERNIA RESERVOIR PARAMETERS

	Upper Zone	Lower Zone
	Avalon/Catalina Sands	Hibernia Sands
1. Average Net Pay	150-250 feet	125-225 feet
2. Average Permeability	200-900 MD	900-1,300 MD
3. Average Water Saturation	15-35%	10-40%
4. Average Porosity	18-30%	12-20%
5. Estimated Range of Field Area over which Average Reservoir Parameters apply	9,000-14,000 acres	7,000-11,000 acres
6. API Gravity	24-31°	35-53°
7. Reservoir Depth	7,200-8,800 feet	11,400-12,700 feet
8. GOR (Average)	400-700 SCF/BBL	900-6,500 SCF/BBL

3.1.3 Hydrocarbon Fluid and Gas Analyses

Limited data was available regarding produced fluid, hydrocarbon fluid and gas analyses upon which to base the conceptual design of the production facilities.

As indicated in Table 3-1, prediction of produced fluid analysis for the Avalon zone is simpler than for the Hibernia zone where a significant variation in Gas/Oil Ratio arises between different areas of the zone. Considerable variation in produced fluids can be envisaged over the life of the Field which leads to difficulties in adopting a design basis for the production facilities, particularly with the application of significant gas re-injection prior to any subsequent sales gas production. Further, given four separate production centres, the produced fluid composition will vary between centres thus complicating a prognosis of Field average data.

Produced fluid data supplied by the Petroleum Directorate is given in Table 3-2. The data does not indicate the wide range of sample compositions which may arise, nor the overall Field average which may be anticipated, additional reservoir study being required.

TABLE 3-2

HIBERNIA FIELD PRODUCED FLUID DATA

Component	Produced Fluid Composition (MOL %)			
	Avalon Zone (Well 0-35)		Hibernia Zone	
	(1)	(2)	(Well B-08)	(Well P-15)
N_2	0.25	0.15	0.34	0.14
CO_2	0.26	0.09	0.98	0.55
H_2S	0.00	0.00	0.00	0.00
C_1	43.33	47.40	57.16	52.26
C_2	4.90	5.59	6.92	5.48
C_3	4.50	4.91	5.04	4.63
iC_4	0.81	0.85	0.83	0.85
nC_4	2.60	2.51	2.35	2.55
iC_5	1.25	1.05	0.93	1.01
nC_5	1.63	1.62	1.23	1.80
C_6^+	40.47	35.83	24.22	30.73
	100.00	100.00	100.00	100.00
Saturation Pressure (psig)	3,100	3,458	5,878	4,260
Temperature (°F)	NA	144	257	NA
API Gravity (15/60°F)				
Total Sample	56.4°	61.8°	88.7°	73.6°
C_6^+ Residue	30.3°	30.5°	34.8°	33.4°
Gas/Oil Ratio (SCF/STB)	663	831	1415	1212

Note: Well P-15; Subsurface Sample PVT Analysis, DST #6
Well B-08; Recombined Sample PVT Analysis, DST #6
Well 0-35(1); Subsurface Sample PVT Analysis, DST #4
Well 0-35(2); Recombined Sample PVT Analysis, DST #7

Given the lack of opportunity for computer process simulation/optimization within this preliminary investigation, the conceptual process flow scheme developed for Study purposes (refer to Section 4.1) is based on experience of similar production facilities elsewhere together with due regard for the above data.

For guidance in considering both the process flow scheme and the operating philosophy for the gas transmission system, the Petroleum Directorate supplied a Field average gas composition based on meter run gas from drill stem testing as follows:

Meter Run Gas (DST) Field Average

Component	MOL %
N_2	0.30
CO_2	0.91
H_2S	0.00
C_1	85.82
C_2	7.24
C_3	3.85
iC_4	0.42
nC_4	0.90
iC_5	0.17
nC_5	0.21
C_6^+	0.18
	100.00

Such gas is within specification, as regards liquid dropout, for the gas transmission system operating philosophy developed in Section 4.4.

3.1.4 Discussion on Reservoir Depletion Parameters

The production data given as input to the Study gives rise to several inconsistencies and anomalies, in particular:

- gas/oil ratios;
- relative production rates between the Avalon and Hibernia zones;
- number of production/injection wells to achieve the stated levels;
- overall level of production given reserves and reservoir definition.

As such the input data given for Study purposes may not be representative of actual Field conditions and should be validated by detailed reservoir analysis.

.1 Gas/Oil Ratios

The gas/oil ratios implied by the production data are:

Production Zone	Produced Gas/Oil Ratio (SCF/STB)
Avalon North	400 (480)
Avalon South	333 (400)
Hibernia North	2000 (2400)
Hibernia South	1111 (1333)
Overall	892 (1070)

The above Field GOR's are net of fuel and other gas usage and for discussion purposes may be increased by, say, 20% for a comparison based on separator GOR's (given in parenthesis).

For information at this time, the overall Field fuel gas usage derived from consideration of the development concept adopted for Study purposes is in the order of 50 MMSCFD when re-injecting gas, which validates the above allowance of 20% (although with a significantly different distribution between production centres).

While the above GOR's are within the anticipated range for the Field (refer to Table 3-1), the Avalon GOR's are in the lower levels while considerable variation arises between the two Hibernia production centres. Detailed reservoir analysis is required based on the anticipated production at each centre to validate the Study data, but this is outside the scope of this preliminary investigation.

.2 Production Rates

Given the Study premises, the oil production rates of the Avalon and Hibernia zones are similar. From published DST data for the discovery and appraisal wells and the areal extent of the zones as published by Mobil[1], it is considered possible that the plateau production rate from the Avalon zone may be twice that from the Hibernia zone (given a reasonable number of wells for efficient reservoir depletion).

With regard to gas production rates, the re-injection of gas prior to making gas available for export, together with the opportunity to produce non-associated gas, implies that gas production rates may be higher for the stated oil production rates than indicated by the average produced GOR's (which will effectively increase with time).

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1. Reference: McIntyre, N.F., "Environmental Forces on a Fixed Platform and the Ability of the Platform to Resist Them", Proc. of the Symp. on Production and Transportation Systems for the Hibernia Discovery, St. John's, Nfld. Feb. 16-18, 1981.

.3 Number of Wells

The number of wells given as input data to the Study implies the following production or injection indices (average):

Production	:	9,333 BOPD/Well
Gas Injection	:	83 MMSCFD/Well
Water Injection	:	27,273 BWPD/Well

The above assumes that all 250 MMSCFD is re-injected in the early years of production and that 300,000 BWPD is required for reservoir pressure maintenance purposes.

The production rate per well is considered close to the limit for the Hibernia zone but is excessive for the Avalon zone, where the low API Gravity may limit effective production per well to, say, 6,000 BOPD. In overall terms an increased number of producers is considered necessary, possibly in excess of twice that given.

For gas injection, an effective limit of, say, 50 MMSCFD per well may be used indicating a requirement for at least 6 gas injection wells.

With regard to the efficiency of water injection, a capability to inject at least 135% of the volume of produced fluids may be required. Given some natural water drive and gas re-injection, in early years this level of injection may not be fully required. If it is necessary to provide such an amount, however, an annual average daily requirement of 380,000 BWPD is demanded based on a production rate of 280,000 BPD. Using an effective injection limit of 15,000 BWPD per well, at least double the number of water injection wells given may be required. The given level of 300,000 BWPD has been maintained for the purposes of considering topside facilities, however.

In overall terms therefore, the total number of wells required for the development is likely to be at least double the number given (44) for the stated production rates.

In the Field development concept adopted for Study purposes therefore, six, twelve slot well templates are provided with the capability of additional satellite wells being tied-in (say 16).

.4 Overall Level of Production

The average level of production given as data input to the Study, i.e., oil production 280 MBOPD; gas production 250 MMSCFD, is provided for the purposes of developing indicative production facilities based on four floating production centres. Notwithstanding the above anomalies, these levels have not been changed for Study purposes and as basic assumptions provide meaningful information concerning possible development and production/export of gas from the Field.

The facilities required are, of course, inherently dependent on the average and peak production rates required and thus the production assumptions adopted must be clearly borne in mind in considering later Sections of this Report.

A brief evaluation of the Hibernia development, made using the EPI field development models, indicates that reasonable reservoir depletion may permit average production levels of, say, 300,000 BOPD together with the gas production in excess of, say, 375 MMSCFD following, say, 8 years of re-injection. Producing the gas reserves at 250 MMSCFD (at a correspondingly reduced oil rate) would require a Field life in excess of 40 years, given 10 years initial re-injection of gas and a reasonable depletion profile. Higher gas production rates than those adopted for Study purposes would therefore seem reasonable, the availability of such gas for export being dependent on a continuing requirement for gas injection for reservoir management purposes. If injection rates are limited and a gas transmission system is not available (or commissioned) then such gas as is not required for fuel or other uses would of necessity be flared.

Further, it is understood that in the reservoir simulation modelling results available to the Petroleum Directorate, the model indicated significant gas cycling through the reservoir. Such an occurrence would significantly alter the Field production characteristics, have a major impact on facilities design and would not be considered good offshore practice.

3.2 ASPECTS OF OIL/GAS UTILIZATION

3.2.1 Introduction

Until recently, associated gas from fields produced primarily for crude oil has been regarded more as a nuisance rather than an additional export product of value. Such gas not required for reservoir pressure maintenance and/or in excess of fuel gas and other usage requirements offshore has usually been flared, or possibly disposed of by re-injection to the reservoir or elsewhere. Re-injection may fulfil a reservoir pressure maintenance function and/or storage for later production. In many cases of associated gas reservoirs, however, significant quantities of gas cannot be injected for extended periods without causing damage to the reservoir and adversely affecting production.

Where oil pipelines have been included in the development plan (and possibly gas pipelines for high Gas/Oil Ratio fields) efforts have been made to maximize the "spiking" or injection of Natural Gas Liquids (NGLs) into the main export lines. This is done within the limits of overall Total Vapour Pressure for oil pipelines and within Hydrocarbon Dew Point Limits for "dry" gas pipelines. The oil/gas process philosophy adopted here for Hibernia would change significantly if an oil pipeline were to be included.

In the last few years, particularly in the North Sea, pressure to reduce offshore flaring has been applied both by national government and by the operators' desire to maximize return on the development. This has been reflected in efforts to implement gas gathering between operators and, in some instances, consideration of the export of condensate by tanker. Considerable interest has developed in high pressure, "dense phase" transmission of "rich" gas by pipeline and research continues into more reliable prediction of multi-phase flow behaviour.

Where oil and gas pipelines have not been available for associated gas export from offshore fields and crude oil has been exported by offshore loading of tankers, gas utilization has been limited to maximizing offshore use and the export of condensate and Liquid Petroleum Gas (LPG), also by means of offshore loading. Such facilities are not, however, common and are restricted in current applications to barge mounted floating facilities in sheltered locations, e.g., the LPG facility installed on Pertamina's Ardjuna Field in the Java Sea, Indonesia. Development plans for the Tyra complex in the Danish sector of the North Sea included condensate export by offshore loading but this has now been eliminated due to the inclusion of both oil and gas pipelines to shore in the development.

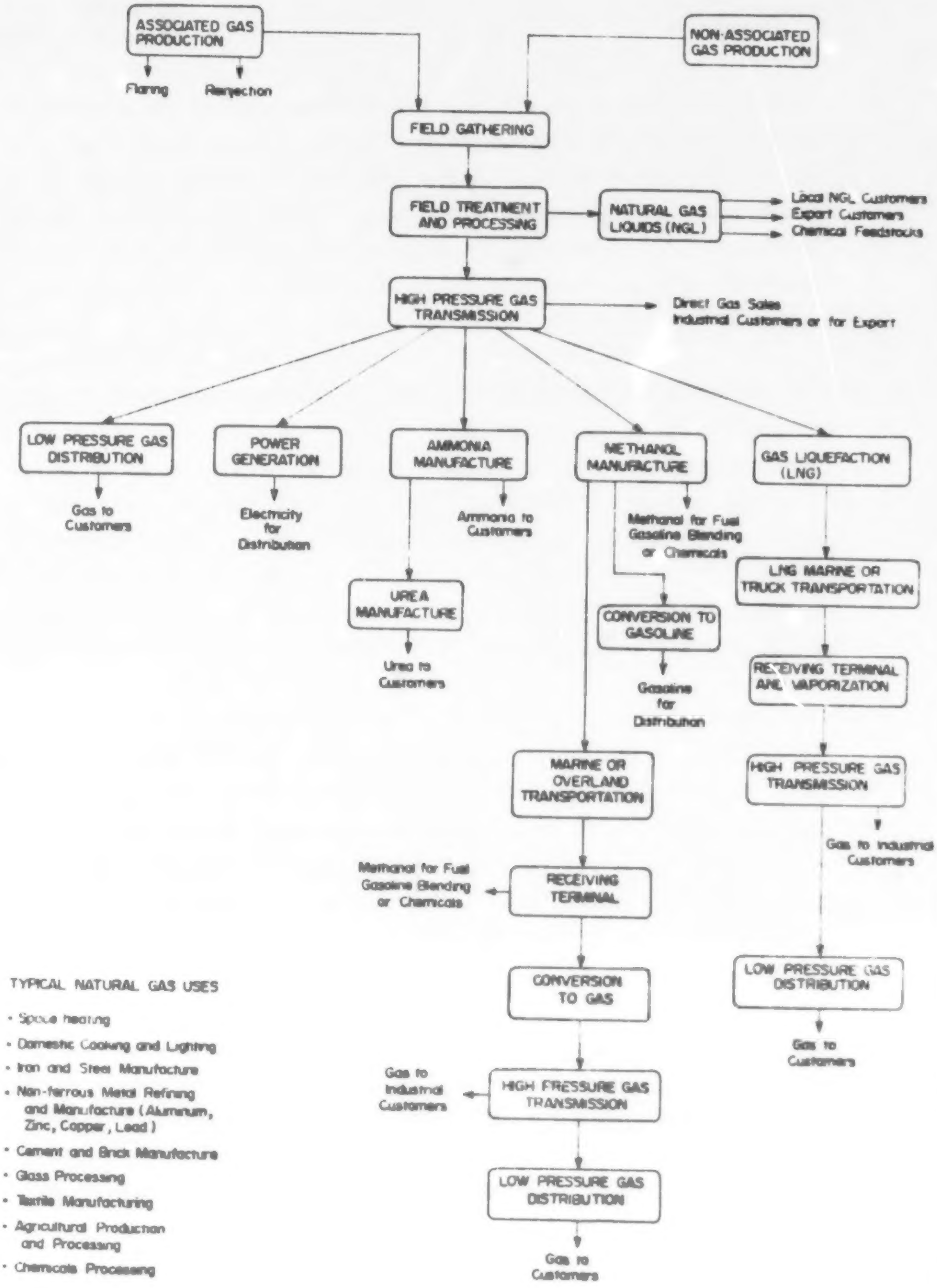
It is of interest to note that alternative gas utilization methods such as the offshore manufacture of Liquefied Natural Gas (LNG) has been proposed since the mid-1960's, but to date no applications exist for offshore fields at remote exposed locations, although inshore barge mounted facilities do exist, e.g., for LNG, methanol and fertilizers.

The possible utilization of gas is illustrated in Figure 3-3.

3.2.2 Aspects of Associated Gas Production

In considering the Hibernia development, it is essential to bear in mind that the principal source of produced gas is that which arises in association with the oil. For oil reservoirs with gas caps, the

ELEMENTS OF NATURAL GAS PROCESSING SYSTEMS


ASSOCIATED GAS PRODUCTION
Flaring
Reinjection
NON-ASSOCIATED GAS PRODUCTION
FIELD GATHERING
FIELD TREATMENT AND PROCESSING
NATURAL GAS LIQUIDS (NGL)
Local NGL Customers
Export Customers
Chemical Feedstocks
HIGH PRESSURE GAS TRANSMISSION
Direct Gas Sales
Industrial Customers or for Export
LOW PRESSURE GAS DISTRIBUTION
Gas to Customers
POWER GENERATION
Electricity for Distribution
AMMONIA MANUFACTURE
Ammonia to Customers
UREA MANUFACTURE
Urea to Customers
METHANOL MANUFACTURE
Methanol for Fuel Gasoline Blending or Chemicals
CONVERSION TO GASOLINE
Gasoline for Distribution
MARINE OR OVERLAND TRANSPORTATION
RECEIVING TERMINAL
Methanol for Fuel Gasoline Blending or Chemicals
CONVERSION TO GAS
HIGH PRESSURE GAS TRANSMISSION
Gas to Industrial Customers
LOW PRESSURE GAS DISTRIBUTION
Gas to Customers
GAS LIQUEFACTION (LNG)
LNG MARINE OR TRUCK TRANSPORTATION
RECEIVING TERMINAL AND VAPORIZATION
HIGH PRESSURE GAS TRANSMISSION
Gas to Industrial Customers
LOW PRESSURE GAS DISTRIBUTION
Gas to Customers

TYPICAL NATURAL GAS USES

- Space heating
- Domestic Cooking and Lighting
- Iron and Steel Manufacture
- Non-ferrous Metal Refining and Manufacture (Aluminum, Zinc, Copper, Lead)
- Cement and Brick Manufacture
- Glass Processing
- Textile Manufacturing
- Agricultural Production and Processing
- Chemicals Processing

J31-1/7575

Figure 3-3

source of the non-associated gas at Hibernia, it is not normal offshore practice to produce the gas cap since this is likely to adversely affect overall recovery from the field. Gas will therefore be co-produced with the oil, gas availability thereby being controlled by the oil offtake level and influenced by the downtime arising from the crude oil offshore mooring/loading export system.

The principal drive mechanism for Hibernia is believed to be a natural water drive. It is possible that, in early years of production, some gas re-injection may be desirable to optimize overall recovery. Detailed reservoir analyses are required to determine such gas quantities together with water injection. Detailed studies are also required to determine the limiting quantities of gas which can be re-injected without adversely affecting the reservoir, both in terms of daily injection rates and duration.

Should it be determined, as a result of detailed reservoir studies that significant gas re-injection is feasible, gas not required for fuel or other platform uses may be re-injected for later production, i.e., deferred gas production. By careful reservoir management, given suitable reservoir characteristics, it may be possible to build a substantial gas cap which may be produced in its own right later in the life of the Field. Under such conditions gas may not need to be exported for, say, up to 10 years after initial production thus permitting the rational development of onshore utilization systems not linked to the project time scale of the offshore development.

Further, the use of Hibernia as a central gathering point for gas from other nearby fields can be considered. Given suitable circumstances, Hibernia gas production may be deferred while third-party use is made by other fields of the Hibernia gas transmission system, should one be installed. Additional quantities of gas from other fields may also possibly be "stored" in the Hibernia reservoir for later production. Such an application may be envisaged closer to the end of the productive life of Hibernia as other fields come on stream, similar to the use of the Rough gas field in the Southern North Sea by the British Gas Council. This would not normally be expected to be undertaken by a commercial operator whose business is production, e.g., in the case of the Rough Field, BGC purchased the facilities and depleted reserves remaining in the Field from Amoco.

Finally, it is also of importance to note that flaring of gas offshore can only be minimized not eliminated. There is always an essential base flaring load, albeit relatively small, and flaring will be necessary in the event of process upsets, significant short term variation in operating conditions, shutdown of gas re-injection or export systems, etc. Also, given the application of floating production facilities and the use of offshore storage/mooring/loading for the export of crude oil, Hibernia cannot be considered a secure supply of gas for non-interruptible purposes onshore.

3.2.3 Alternatives For Offshore Gas Utilization

Numerous studies have been carried out into all forms of offshore gas processing in the absence of a gas pipeline to shore, e.g.:

* Liquefied Natural Gas (LNG);
  - light and heavy
* Methanol;
* Ammonia/Urea;

- Fertilizers;
- Ethylene;
- Acetylene;
- Carbon Black;

among others, as well as power generation.

The prime options for gas utilization, in the absence of pipelines and assuming that offshore gas usage for fuel and other uses is maximized, are:

- LNG;
- Methanol;
- Power Generation;

in addition to possible separate export of condensate and/or NGLs or spiking of NGLs into a crude oil export line.

In principle, LNG is the most likely option to be preferred based on market and volume considerations. However, it is also the most complex and least proven technology. Comparing the relative technical merits of each option leads to the following conclusions:

LNG	- most complex requiring low temperature storage and as yet unproven handling systems.
Methanol	- stable at atmospheric pressure and ambient temperatures requiring only conventional handling systems, but particularly susceptible to vessel motions for floating systems.
Power Generation	- simplest facilities with uninterrupted transmission capability (compared to LNG and Methanol which depend on shuttle carriers and mooring/loading systems) but lowest overall thermal efficiency.

Methanol is likely to be preferred to ammonia or urea due to its stable characteristics for storage and export and reduced equipment and space requirements. Market considerations are, of course, important in influencing selection.

Of particular importance in evaluating the above options is the question of total utilization of gas residual to the oil and gas separation facilities.

First, due to additional gas usage requirements, energy losses in the process, and potential losses during handling, the quantities of gas exported are reduced compared to the original volume available. For example, the following overall thermal efficiencies may apply (in order of magnitude terms):

LNG - 80%
Methanol - 60%
Power Generation - 40%

Further potential losses arise during transport/transmission to shore, e.g., LNG boil-off (limited by possible ship fuel usage or re-liquefaction), electric cable losses.

Secondly, operation of the plant will inevitably lead to some transient increases in flaring, or shutdown of the oil/gas separator facilities if excessive flaring is not permitted, due to the following circumstances:

* total or partial shutdown of the gas plant while the oil plant is available;
* start-up losses;

- maintenance and repair; and
- less-than-optimum operating conditions.

Thirdly, for systems relying on shuttle carriers for export, a significant reduction in overall efficiency will arise at exposed locations due to adverse environmental conditions. Storage may need to be included in the system, together with uprated overall system characteristics, e.g., size and number of shuttle carriers, to achieve acceptable performance levels.

In the latter two points above, these are real energy losses arising from flaring unless the oil plant is shut down or the gas re-injected or stored.

Further to the above, while some claims are made for total utilization by heavy LNG system designers, they still usually require removal of significant amounts of heavy hydrocarbon fractions from the gas prior to processing. This will require separate export of condensate and/or NGLs depending on the composition of the gas residual to the oil/gas separation facilities. Proposals have been made for combined export of crude oil and stabilized condensate in shuttle tankers, but this would reduce the number of onshore discharge points.

Total utilization is, therefore, open to interpretation. It is evident that while it is theoretically possible to install facilities which will reduce flaring or residual gas to "zero" except in emergencies, this will rarely be economic nor achievable in practice. Even were it feasible to install facilities with a potential for total utilization, plant operation is never ideal and partial shutdowns and situations giving rise to operation at below optimum conditions will always mean flaring in the long term cannot be "zero". Rather, facilities design should be such that the average flaring rate is reduced to an acceptable, safe, practical and economic minimum in the long term.

Further, provision must be made for emergency flaring.

For any specific development, the design production rate and the operating range must be established, together with feedgas quality and composition. Production rate and composition as well as other production characteristics, such as wellhead pressure, vary over the life of the field. Gas processing plant is usually designed for peak production and will, therefore, operate for most of its life below capacity. A reasonable productive life for the gas facilities within the overall productive life of the field requires a relatively low turndown capacity for the plant, say, 25% or less. The plant would be shutdown either when this limit is reached or when gas availability is sufficient only for gas usage, or as dictated by operating economics.

Where the product is sold on a contracted annual quantity basis, then this will also condition design and operational aspects to ensure delivery of the required annual average production, which must take into account production losses. The fact that associated gas production is necessarily linked with oil production introduces a further complication, particularly when contractual obligations for gas must be met. This may place unacceptable constraints on oil production from the operator's point of view. For systems based on offshore loading, if storage is included in the oil system and flaring is to be minimized, then the gas utilization system must also include storage.

In general four specific reasons arise as to why operators are now more concerned than previously to reduce flaring:

i) Government requirements

ii) Desire to optimize "hydrocarbon" rather than oil recovery

iii) The increasing value of gas (which in some contracts is now valued on a parity basis with a 'basket' of crude oils and/or products).

iv) Pipelines may not be technically feasible or acceptable.

The trend, however, is still against offshore gas processing whenever a pipeline can be installed (as was concluded in the Fulmar Field Study by Shell Expro UK). Most alternative utilization concepts are applied to marginal associated gas sources where gas availabilities may be less than, say, 100 MMSCFD. LNG, however, is applicable to much larger sources, principally because of product market volume. None of the conceptual designs have found application to date however, unproven technology and economics playing a deciding role.

However, with the potential development of Canadian reserves where pipelines are not acceptable, offshore processing presents the only method of export. This has particular relevance to the Hibernia development.

3.2.4 Onshore Gas Utilization

The development of low Gas/Oil Ratio oil fields or high Gas/Liquids Ratio gas fields is relatively straightforward in terms of the interaction of onshore and offshore facilities. Oil fields with significant quantities of associated gas present a much more complex design/economics problem due to the different priorities which may be given to oil and gas production, the trade-offs between the extent of processing carried out offshore versus onshore and the difficulties of optimizing recovery from the overall resource.

Significant engineering resources are required during a project to determine the extent and method of offshore processing to meet the required specification for landed products in terms of crude oil, gas and Natural Gas Liquids at the boundary fence of the onshore processing facilities. Knowledge of the end-use for landed products is therefore an essential requirement in determining the overall field development plan. Such will be the case for the Hibernia Field if gas export is a criterion for development in addition to oil export by tanker loading.

At present, the end-use of offshore gas landed in Newfoundland is not defined and thus no requirement can be stated for landed gas specification. For Study purposes therefore, as discussed in Section 4.0, the assumption is that the gas transmission design objective is to handle a wide range of gas compositions including a condensing, relatively "rich" gas. Trade-offs will arise between onshore versus offshore processing given the "rich" gas, transferring most gas processing onshore. It should be noted that even with "dry" gas, some onshore processing is still likely to be required.

As the Hibernia project is defined, it will be important to examine the overall oil and associated gas economics and financial viability for the specific field development plan. The overall economics of exporting associated field gas may have negative economics, and only when the gas utilization/export scheme is evaluated in combination with the oil production scheme can a more indicative set of economic parameters can be developed.

The marketability of the end products, whether they are in the form of dry "specification" gas, LNG, methanol, ammonia, electricity, etc., will be a significant factor on the selection of gas utilization alternatives. For example, if there is a very limited market for methanol and low expectations that this market will expand during the late 1980's and 1990's, then it would be meaningless to produce methanol whether onshore or offshore.

Hibernia gas will need to be considered within the overall Eastern Canada context. LNG may have to compete with natural gas produced from the Sable Island gas fields, particularly if the LNG produced either onshore or offshore has to be landed in Eastern Canada. The projected natural gas demand for the Maritime Provinces remains fairly low through to the year 2000, and excess gas volumes would have to be exported to the U.S.A. to provide the producers with sufficient economic incentives to implement offshore LNG processing and transportation systems. Petrochemical plant viability for locations in Newfoundland or Nova Scotia would also have to be evaluated. Regassification of offshore produced LNG in Newfoundland for electrical power generation may also have to be examined. Underground (salt dome) storage of natural gas in Cape Breton may be unattractive to supplement peak gas distribution in the Maritime Provinces area. Regassified "offshore" LNG would have to directly compete with coal in Nova Scotia for additional electrical power generation. These are just some of the other considerations for "end use" that will have to be evaluated in conjunction with the specific technical details of the offshore gas utilization facilities.

The overall economic and strategic considerations for a typical Hibernia Field associated gas would include:

- magnitude of associated gas reserves and the pace of development;

- * natural gas export, domestic markets and pricing;
- * implications of East Coast Canada supply of gas on existing and proposed transmission systems (TQ&M) Sable Island Gas Development, and on Western producer markets;
- * relative value of Hibernia associated gas when compared to other energy projects, i.e., Sable Island, incremental western basin supplies;
- * natural gas liquid markets, prices, supply/demand expectations;
- * petrochemical industry opportunities and viability (methanol, ammonia, etc.);
- * producer economics, impact of NEP and taxation proposals;
- * transportation economics; and
- * benefit/cost implications.

In summary, principal onshore end-use options are:

- * Domestic Consumption;
- * Industrial Consumption;
- * Power Generation;
- * Petrochemicals;
- * Liquefaction for Re-Export.

Of key significance with regard to possible options is:

- * The Security of Supply
- * Anticipated Annual Average and Peak Gas Quantities Landed
- * Depletion Profile
- * Composition of Landed Gas

Considering the Hibernia Field in isolation, its characteristics as an associated gas source cannot be considered as a secure supply for non-interruptible end-use purposes, such as domestic consumption. Further, supplies of NGL from Hibernia will not be sufficient to support a large scale petrochemical complex. Typically, a world-scale petrochemical complex would require, say, three million tons per annum of crude NGL for a period of some 15 to 20 years to attain the needed economics of scale and integration. For comparison, as regards onshore processing facilities dedicated to specific associated gas sources, the design of the FLAGS pipeline in the North Sea delivering associated gas from the Brent Field to St. Fergus, Scotland, is based on the average export of 800 MMSCFD of gas (methane) plus 2.5 million tonnes per annum of NGL (ethane, propane, butane and some natural gasolines) which will be separated at Mossmorran, Scotland. NGLs from the potential Hibernia associated gas supply of 250 MMSCFD (gross average) may therefore at best supply only part load on an interruptible basis for petrochemicals.

At present, therefore, the most immediately applicable end-uses for Hibernia gas in Newfoundland would appear to be:

- Industrial Consumption;
- Power Generation;
- Liquefaction for Re-Export.

The application of other uses will depend on the overall industrial development philosophy prevailing in Newfoundland, as well as on potential supplies of additional gas and NGLs from other offshore sources.

3.3 DEVELOPMENT ALTERNATIVES

3.3.1 Introduction

The principal objective of this preliminary investigation is the evaluation of the production and transmission of gas from the Hibernia Field.

In its simplest terms, the above objectives would be met by considering only the transmission system and its associated equipment requirements offshore since the gas which may become available for export is essentially a co-produced by-product of oil production, i.e., associated gas. However, it is not considered reasonable to evaluate gas transmission in isolation from the overall field development concept since the total field production facilities must comprise an integrated system.

The alternative methods of developing the Hibernia Field have received considerable attention in the technical press and in the Symposium organized by the Petroleum Directorate in 1981. The main objective of most presentations has been the production of oil from the Field. Little attention has been given, until recently, of the possibilities of making gas which is surplus to offshore usage requirements, i.e., re-injection for reservoir pressure maintenance, fuel gas and other platform gas demand, and possibly future gas lift, available for export.

It is important to note that this investigation has not considered possible gas export facilities simply as an "add-on" to a field development plan designed to produce oil. The conceptual development plan adopted for Study purposes includes gas export as an integral part of the system, this having an influence on the general facilities configuration assumed. However, it is of interest to note here that the inclusion of gas export systems to the overall concept requires minimal additional equipment within the Field compared to that required in any event for oil production and gas re-injection, accepting the facilities configuration assumed.

3.3.2 Functional Requirements

The principal functional requirements of the Hibernia development within the context of this Study are:

i) Oil/Gas Separation
ii) Stabilized Crude Oil Export by Offshore Loading
iii) Gas Export by Submarine Pipeline Transmission
iv) Water Injection
v) Gas Re-injection (not simultaneous with gas export)

Clearly, all the usual additional requirements for offshore field development are also demanded, e.g., utilities, accommodation and life support systems, etc. There will also be the requirement for development drilling and well maintenance/workover.

As noted in Section 3.2, the utilization of the landed gas may have considerable influence on the offshore facilities, particularly where a "dry" gas is required to be produced offshore. This has not been assumed for Study purposes, the possibility of liquid drop-out in the submarine and onshore pipeline being accepted and accounted for. There will therefore be a requirement for onshore gas purification and further processing the extent of which will depend on the eventual usage of the gas. For the purposes of this Study, such purification and processing has been assumed outside the battery limit of the onshore gas reception facilities. The requirements for gas reception onshore, e.g., liquid slug catching pig/sphere reception, emergency vent/flare, are included in the scope of the investigation.

3.3.3 Development Alternatives

It is not within the scope of this investigation to evaluate all the different methods of developing the Hibernia Field, including gas export. Rather, following a brief review of the alternatives, an overall development concept is adopted which is considered reasonable given the particular production requirements of the Field and the physical characteristics of the location.

With regard to support structures, the anticipated level of production and the water depth and weather at the location would normally result in the application of fixed structures, i.e., piled steel jackets/towers or gravity platforms (concrete or steel). The particular risk of iceberg collision with support structures has been paramount in the proposals (by others) for Hibernia applications. It is considered that, at present, insufficient published data is available on the statistical level of risk, e.g., the 100 yr. iceberg collision risk as compared the usual design criteria offshore, the ability of fixed structures to resist impact and methods of moderating the risk and magnitude of its occurrence, to unequivocably exclude fixed structures as a development possibility. A comparison with the risk and practices adopted in association with hurricane occurrence in the Gulf of Mexico may warrant consideration, as long as the correct perspective is maintained between the two cases.

The inclusion, subject to technical feasibility, of a fixed structure in the development plan, and acceptance of the iceberg collision risk, would simplify the problem of selecting a development concept since the question of the co-production and export of gas with oil would essentially reduce to one of economics alone due to the capability of a fixed structure as regards deck load and use of fixed risers. Further, major storage may be integrated with gravity based structures. The alternative of a single fixed structure used in conjunction with several floating production centres, as well as full development by fixed structures, may be considered.

However, given that the acceptable application of fixed structures is by no means established, and consideration of which is outside the scope of this Study, the field development concept adopted for Study purposes includes floating production platforms (FPP's) only.

The key decision in the application of floating production facilities is between ship-shape, semi-submersible or buoy-like support structures. Novel designs for large semi-submersible platforms such as Norcon's "CONPROD" and buoy-like platforms such as Trosvik's "BIG BUOY" have been excluded whether constructed in steel or concrete, due to their unproven nature. The designs have merits, however, principal of which are high deck load and oil storage capabilities, but draught limitations may apply in the moderate Hibernia water depths. Tension Leg Platforms (TLP's) are also not considered applicable due to limiting water depth and inability to disconnect at short notice.

The use of ship-shape support structures merits consideration whether converted tankers or purpose built. They exhibit high deck load and deck area capabilities with integral oil storage, have excellent mobility and are capable of surviving extreme sea conditions (particularly when underway). Alternative mooring approaches include turret systems, whether built into a moon-pool or fixed to the stem of the vessel, submerged SALMs (single anchor leg moorings) and rigid yoke systems. The most advanced design of such a system is that due to Blehr and Tenvig Offshore A.S. who propose a turret moored production/storage tanker with a submerged adjustable pontoon motion stabilization system (BT MM). To support a production rate of 100,000 BOPD, a 100,000 ton dwt. tanker would probably be required providing storage for 300,000 barrels of oil assuming segregated ballast tanks. While ship-shape vessels offer significant advantages over conventional configurations of semi-submersibles, i.e.:

* high deckload/deck area capacity
* high integral storage capacity
* excellent mobility/survivability
* simpler maintenance
* lower construction cost

the motion characteristics of the unstabilized ship-shape vessel are excessive in severe environmental conditions as regards overall process efficiency and limiting production riser response. Blehr and Tenvig claim that with motion stabilization production may continue up to sea states at least comparable to those limiting semi-submersibles in environments similar to the northern North Sea. The application of such a system to Hibernia can therefore be envisaged, several such vessels being required. Close attention should be given to the continued development and proving of the system with particular reference to long term structural integrity and the feasibility of mooring such large vessels in the severe environment of Hibernia and maintaining reasonable operational efficiency. However, such a ship-shape vessel has not been adopted for floating production platform use for Study purposes due to its unproven nature.

Semi-submersible floating production platforms of conventional configuration have therefore been adopted for Study purposes, to some extent by default since the limiting deck payload/area and low integral storage capability of such vessels is not ideal for the Hibernia development. Such semi-submersibles would be at least the size of those currently available as exploration rigs (depending on number of FPP's used) and would be purpose-built. The design and operating procedures for such vessels will need to be to high standards to ensure the long-term safety of the development, particularly in the light of the recent "Ocean Ranger" disaster on the Grand Banks. The dynamic and damage stability of the FPP's will be of paramount importance.

Given the assumed adoption of semi-submersible FPP's for the development, there will of necessity be extensive use of subsea production systems and equipment, together with a requirement for separate crude oil storage to reduce system downtime due to weather.

Floating storage has been assumed, the conventional facility in more moderate environments being a converted tanker yoke-moored by the stem. The turret or submerged SALM moored tanker can be envisaged for the Field with the advantage that emergency disconnect would be simpler and subsequent integrity of the mooring system more predictable. The feasibility and potential efficiency of mooring large tankers in the severe Hibernia environments is not established at this time. It is noted that Mobil have proposed a novel, column stabilized, yoke-moored storage tank as one possible solution. Due to the high level of production from the field several separate storage units may be required providing several million barrels capacity to reduce effective downtime of the oil export system to below 10%. No conclusion on preferred storage method can be made at this time without more detailed investigation. Therefore, tanker based systems have been adopted due to their proven operational and survival capability as marine vessels together with good, independent mobility, given the retention and maintenance of the main propulsion system, but with reservations on their application specifically to Hibernia.

The above discussion outlines the reasoning behind adoption of particular types of support structures and storage systems for Study purposes. It is emphasized that selection of these basic components of field development has not been based on a rigorous evaluation procedure which is an essential part of field development planning. Rather, a reasonable selection has been made in order to proceed to the primary objectives of the Study, the preliminary investigation of gas production and export within an integrated development plan. Detailed field development planning studies including evaluation of technical feasibility and economics of the total system may indicate a preference for some alternative development approach.

3.4 CONCEPTUAL FACILITIES CONFIGURATION

An artist's interpretation of the conceptual facilities configuration adopted for Study purposes is shown in Figure 3-4.

Using semi-submersible FPP's of conventional configuration, a minimum of four production centres is considered necessary to maintain the topside payload of individual FPP's within reasonable levels, say, 10,000 tons to 15,000 tons. The FPP locations have been adopted as shown in Figure 3-2, bearing in mind that given the use of remote well clusters and satellite wells, FPP location depends more on reasonable inter-platform separation and moderate flowline lengths than on well targets. Depending on actual design production rates and functional requirements as arising, the need for a fifth FPP can be envisaged possibly supporting centralized water injection/gas handling equipment, or simply an additional production centre.

As a basic premise, production and injection wells have not been located directly beneath the FPP. This has the advantages of:

- optimum wellhead/cluster location with reference to the reservoir independent of FPP location;
- permitting drilling and workover of wells to be carried out without significant production shutdown;
- eliminating the necessity for a workover capability on the FPP's with the consequent advantages of topside weight and spacing savings and reduced riser handling system complexity;
- reducing the risk of wellhead damage due to items dropped from the FPP or attendant service vessels.

The arrangement increases the risk of damage due to anchors, etc., to both wellheads and the increased number of flowlines on the seabed but such a risk may be minimized by proper operational procedures and by burial of the in-field lines.

At least one dedicated drilling/workover rig will be required for the life of the Field such a rig preferably also being used for development drilling (in addition to other rigs being chartered as required).

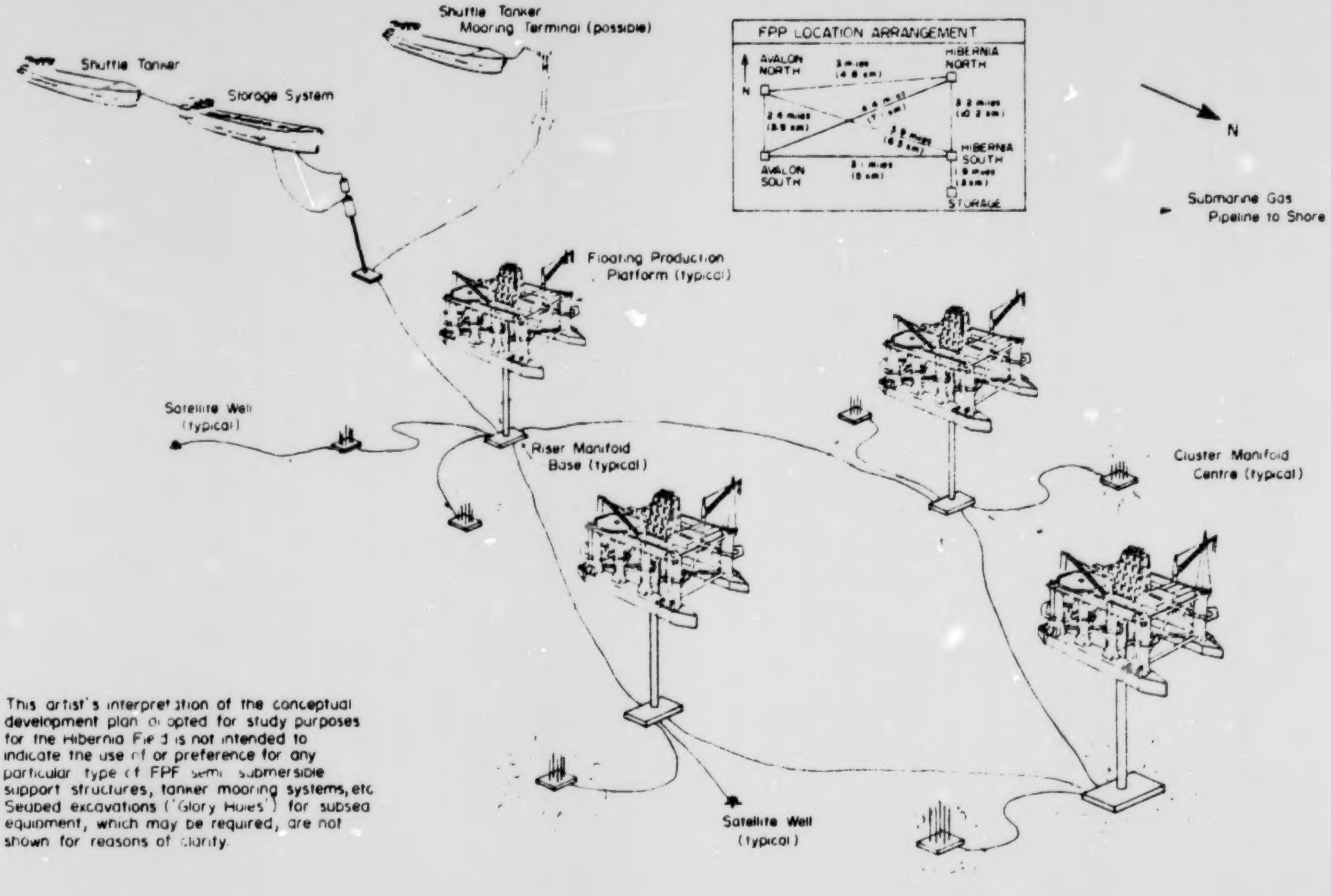
Six, twelve-slot Cluster Manifold Centres (CMC's) have been included; two each tied-back to Avalon South and Hibernia South, one each to Avalon North and Hibernia North. The CMC's include the capability to tie-in satellite wells as required on a modular basis, such wells being required where CMC slot capacity is exceeded or where well targets cannot be reached by deviated drilling from the CMC's. Typically, water injection wells may be satellites as could for convenience be the small number of gas injection wells required, thus reducing the complexity of the CMC's.

Twelve slots are considered reasonable in terms of extending existing subsea technology and since the large areal extent of the Field may be more readily encompassed through the use of a number of smaller well clusters rather than, say, four large clusters.

The CMC's are tied-back to their respective FPP's via a pair of bundled flowlines/control lines to a Riser Manifold Base (RMB) beneath the FPP, and connected to the production deck by an integral riser.

Depending on detailed evaluation of merits and disadvantages, the CMC's and the RMB may be installed below the seabed in subsea

HIBERNIA FIELD - CONCEPTUAL FIELD DEVELOPMENT FACILITIES (An Artist's Interpretation)


Shuttle Tanker
Mooring Terminal (possible)
Shuttle Tanker
Storage System
FPP LOCATION ARRANGEMENT
AVALON NORTH
N
3 miles (4.8 km)
HIBERNIA NORTH
2.4 miles (3.9 km)
4.4 miles (7.1 km)
3.2 miles (10.2 km)
3.9 miles (6.3 km)
AVALON SOUTH
3.1 miles (5 km)
HIBERNIA SOUTH
1.9 miles (3 km)
STORAGE
N
Submarine Gas Pipeline to Shore
Floating Production Platform (typical)
Satellite Well (typical)
Riser Manifold Base (typical)
Cluster Manifold Centre (typical)
Satellite Well (typical)

NOTES 1 This artist's interpretation of the conceptual development plan adopted for study purposes for the Hibernia Field is not intended to indicate the use of or preference for any particular type of FPF semi submersible support structures, tanker mooring systems, etc

2 Seabed excavations ('Glory Holes') for subsea equipment, which may be required, are not shown for reasons of clarity.

Figure 3-4

excavations with the objective of reducing the risk of iceberg scour damage. Such evaluation should also include the necessity to provide protection to the CMC's from the risk of anchor damage.

The flowline bundles would likely be trenched to provide some protection from small anchors and anchor chains. This would also be an advantage should produced fluid pour point problems arise in providing thermal insulation to maintain flowing temperatures.

For illustration purposes a single storage tanker system has been shown located to the south of the Hibernia South FPP to reduce the risk of collision arising between a drifting tanker (storage or shuttle). A detailed study of the location environment will be required to determine the "best" position for the storage system subject to prevailing winds, currents and predominant wave directions, no single position providing absolute security. A reasonably distant location remote from the FPP's is therefore been indicated, subject to detailed study.

For use during moderate weather conditions, an "over-stern" mooring has been shown for shuttletanker loading from the storage system. In addition, a remote shuttle tanker mooring/loading terminal is indicated, such a terminal having an increased limiting operational seastate compared to "over-stern" transfer. These two transfer systems may be used in parallel as required. However, given the anticipated production rates, multiple shuttle tankers are likely to be required (as well as possibly multiple storage units) and the number of remote mooring/loading terminals may be increased. Arrangements may also be made for side-by-side mooring.

3.5 CRITICAL AREAS OF THE DEVELOPMENT CONCEPT

3.5.1 General Considerations

The inclusion of Floating Production Facilities in the development concept is not intended to indicate any preference for such facilities compared to the use of fixed platforms. Rather, as a basic premise, it is logical to assume that were a fixed platform designed to be suitable for use at the Hibernia location, then gas export facilities could be readily incorporated into the offshore facilities due to the high deck load and space capability of such platforms, and the elimination of the complex, high pressure, FPF riser systems.

In conjunction with a fixed platform, the technical feasibility and acceptability of gas export would essentially reduce to the critical areas of risk of pipeline damage due to iceberg scour, in conjunction with overall development economics.

Further, the adoption of semi-submersible FPP's of conventional configuration compared to the use of other types, e.g., ship-shapes or large novel semi-submersible/buoy-like floating structures, is not the result of detailed evaluation of the alternative concepts which should be undertaken as a separate study area. Rather, the conventional semi-submersible has been adopted by virtue of its proven nature for use in severe environments, its known stability for use as a production work platform, its suitability for incorporation of major riser systems, and the apparent favour given to such structures by investigations carried out by others to date.

The inclusion of four similarly sized FPP's in the development concept is adopted as a premise as the result of previous work carried out by others and is not the result of investigation into alternative arrangements. The premise was accepted as reasonable in the early stages of the investigation but alternative arrangements may be equally applicable, e.g., one large FPP carrying out all water and gas injection functions with several satellite oil/gas separation centres, or four independent FPP's each with its own oil/gas separation facilities, and water and gas injection capabilities as required. The inclusion of a fifth platform in the Field may also be worthy of consideration if detailed design imposes limits on the topside payload capability of the semi-submersible or if centralized water injection and gas treatment/compression is considered.

The arrangement adopted for Study purposes is considered reasonable in the light of available data and offers a logical division of functions between FPP's and advantages in terms of centralization of gas handling facilities, albeit with an increased, but indeterminate, risk of damage due to iceberg scour.

Of critical importance to the development is the unquantified risk of damage due to iceberg/facilities interaction and the relative risk compared to alternative arrangements. The risk to the FPP's from iceberg collision is common to all alternatives, reduction of risk being achieved by avoidance through disconnection from the subsea equipment.

It is accepted that the overall concept adopted for Study purposes, i.e., Clustered Manifold Centres remote from the FPP and considerable transfer line interconnection between the four FPP's incurs a higher risk of damage due to iceberg scour than where the FPP is located directly over the well and each FPP is an independent facility. The relative risk may be significantly reduced, however, through the trenching of flowlines and transfer lines to the greatest extent achievable using conventional jetting or mechanical equipment which may be capable of operating in the soils anticipated at the location. As for trenching of the main submarine gas pipeline, determination of the required and achievable depth of cover and the suitability of existing trenching equipment will require detailed investigation on the level of risk, the engineering properties of the soil and the establishment of an iceberg scour design criterion, e.g., the 50 or 100 year scour.

As discussed in Section 3.4, each of the alternative concepts of remote or vertical access to CMC's, and independent FPP's compared to shared functions between FPP's, has its own advantages and disadvantages. The principal reasons for the adoption for Study purposes of remote CMC's and shared functions primarily relate to minimizing the complexity of the topside requirements for each FPP, and on obtaining a reasonable topside weight distribution between the four FPP's, to minimize the possible size of the largest FPP required.

In particular, it should be noted that the inclusion of gas export facilities is simplified by centralization of the compression facilities and hence influences the general arrangement.

Whatever the development concept selected, it will be vital to carry out a complete hazard,safety, reliability and operability evaluation of the proposed plan to ensure that the concept satisfies a rigorous set of acceptance criteria. Such criteria will have particular reference to the survival of the facilities and the safety of personnel. A comprehensive list of design accidental events would be complied and the concept "tested" against each event for acceptability. For example, the FPP concept must be such that a design accidental event will not impose a danger to personnel outside the immediate vicinity of the accident. If external protection measures (e.g., fire fighting vessels) are necessary to satisfy the criterion, then these would be assumed to be non-effective for a pre-determined period after the start of the design accident event. Typical design accidental events include:

* Rupture of the main gas pipeline
* Rupture of high pressure riser gas lines
* Rupture of pressure vessels
* Crane accidents and dropped objects
* Helicopter crashes
* Ship or iceberg collisions
* Earthquakes

It is important that any critical safety related control functions should be located in sheltered areas.

3.5.2 Integrated Systems Approach to the Study of Hibernia

Of critical importance at this time, however, is the lack of full and consistent data on reservoir and production characteristics. While the data available to the Study is sufficient to enable order-of-magnitude conclusions to be drawn as to the integration of gas export facilities with the oil production facilities, it is important to note that a not inconsiderable increase in production rates at each location, say, 15%, would require a complete review of the FPP topside facilities with respect to weight and space requirements. A significant increase in design capacity, which may cause topside payloads to increase well in excess of 10,000 tons for particular arrangements, would require a review of the complete development concept and may result in the excessive extrapolation of known technology for conventional semi-submersibles and introduce a possible requirement for a fifth production centre. Significant increases in water injection requirements will also add considerable weight and space requirements and would substantially increase fuel gas demand.

It is considered essential that a consistent reservoir analysis be developed for the Hibernia Field at the earliest opportunity and that the number of wells required, well productivity and pressure maintenance requirements be established with some degree of confidence. The premises upon which this preliminary investigation is based should then be reviewed and the impact on the development concept adopted for Study purposes be assessed. Only by adopting an integrated systems approach to the study of the Hibernia Field development using the most recent consistent set of production criteria can a realistic assessment of the total development be made.

It is emphasized that the development concept adopted for Study purposes is not the result of detailed comparison, evaluation and selection of the total development alternatives which may be envisaged. Such an extensive study is not within the scope of this preliminary investigation. Essentially, a full Field Development Planning Study of the Hibernia Field is required, the scope of which should extend from the reservoir, through alternative well completion and production facilities, to alternative product transmission systems and onshore usage. Full techno/economic evaluation of the alternatives is required, the conclusions being reviewed and revised as reservoir knowledge is improved or as external factors vary, e.g., oil/gas price or taxation. Such a study would ensure that the total development is considered as an integrated system rather than as isolated components the interfacing of which may not be readily apparent.

In connection with the above, and the distribution of functions between FPP's, the possibility that individual production centres may become fuel gas deficient must be considered, particularly as production declines and it is necessary to maintain a full water injection programme. This must be considered for any development concept but given the arrangement as adopted, medium pressure gas may be re-distributed about the Field if required.

3.5.3 Development Phasing

Finally, this preliminary investigation has implicitly assumed that the entire Hibernia Field is developed as a single project, phasing of production build-up to plateau rates being dependent only on the practicalities of construction and installation.

Phased development of the reservoir should be considered since:

i) Considerable reservoir evaluation remains to be done and additional production and reservoir data may be obtained through an Extended Production Test (EPT) approach.

ii) Considerable benefit may be gained from the early operation of a limited production facility in the Field in terms of FPP and Riser design in the severe environments expected, as well as establishing operational procedures.

iii) The magnitude of the total development as a subsea production system has no precedent.

iv) Phased development may extend the lead time required to develop fixed platform designs or improved subsea equipment protection methods.

The reservoir characteristics at Hibernia may permit the separate production of non-pressure related zones, e.g., Avalon or Hibernia. The extent of initial production must consider the possible impact on overall recovery from the Field both in terms of damaging effects on the reservoir and possible increased recovery from improved knowledge of the resource.

Should the Avalon zone be selected for initial production, the lower GOR compared to Hibernia zone would not support a gas transmission system but, given the extent of water injection required, gas flaring after fuel gas usage would be mininal (assuming gas injection is not essential to the Avalon zone and gas compression equipment is not installed).

Subsequently, the Hibernia zone may be developed, possibly in conjunction with a gas transmission system, sufficient lead time having been achieved to determine onshore usage requirements and the possible availability of gas from outside the Hibernia Field. At this time, any fuel gas deficiency at the Avalon facilities may be supplied from the Hibernia zone, including gas lift if this becomes necessary.

Phasing of the development offers the above benefits and may possibly ease the approval procedure since an incremental approach may be adopted. Extended phasing and incremental development may reduce the expected economic returns and would have to be examined in detail. A balance would have to be selected between social, industrial and economic objectives.

SECTION 4

PRODUCTION AND EXPORT SYSTEMS DESIGN PHILOSOPHY

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4.0 PRODUCTION AND EXPORT SYSTEMS DESIGN PHILOSOPHY

4.1 CONCEPTUAL PROCESS FLOW SCHEME

4.1.1 Functional Considerations

Prior to development of the process flow philosophy for each of the four, individual production centres, it is necessary to consider the overall disposition of facilities within the Field. In general, the decision must be made between:

i) Self-contained production centres
ii) Centralized functions
iii) Equitable function/topside load disposition between centres

Previous studies by others related only to oil production have assumed each production centre to be self-contained when using floating platforms. Proposals for development which have included a fixed platform have centralized functions to a great extent, particularly where storage can be integrated into the fixed structure, as in concrete gravity types. The floating production centres associated with such a fixed structure may thus function simply as wellhead manifold/control centres or may include initial separation equipment at a reduced level of complexity compared to the full oil/gas separation requirements.

A considerable amount of water injection is required for reservoir pressured maintenance (at least 300,000 BWPD) with a trend for a significant proportion being required, or accessed from, the South-West Quadrant of the Field. Given a fixed production structure, its location at Avalon South, with centralized oil storage/export and water injection facilities, therefore has attractions. Further, gas injection/export facilities could also be located at Avalon South due to the high deck load capability of a fixed structure. Given the adoption of four, floating production centres, such centralization is not possible without including an extremely large semi-submersible or "buoylike" floating structure at Avalon South. Such a structure would require novel design and development and may be draft limited in the 280 ft. water depths encountered at Hibernia. Alternatively, a turret moored tanker may be utilized at an increased risk of downtime due to motions (subject to the proving of ship-shape vessel motion stabilization devices).

Large semi-submersibles of conventional configuration have been assumed for Study purposes (refer to Section 3.3). A reasonable deck payload target of 10,000 tons has been assumed, implying structures of similar size to the largest drilling rigs available at present with operating displacements in the order of 40,000 tons.

Preliminary investigation of topside area and load dispositions indicates that only limited centralization could be achieved with such structures due to weight and space limitations. Further, establishing self-contained production centres would require the installation of both water and gas injection facilities at least at Avalon and Hibernia South. This was not considered desirable due to:

i) increased overall deck loads and space requirements; and
ii) unnecessary duplication of equipment.

The inclusion of gas export in the development concept, and the possibility to accept incoming gas from fields other than Hibernia, indicated the desirability for at least centralizing gas injection/export compression facilities. Hibernia South is the most attractive location for gas handling due to its areal proximity to the envisaged Hibernia North gas injection well targets, and the higher proportion of total gas being derived from the Hibernia reservoir zones.

The disposition of principal functions, as adopted for Study purposes, is therefore as follows:

	Production Centre Locations			
	Avalon		Hibernia	
Function	North	South	North	South
Production Facilities	*	*	*	*
Water Injection Facilities	*	*	-	-
Gas Injection/Export Compression	-	-	-	*
Produced Water Treatment	*	*	*	*

Since in the early stages of production insufficient produced water will be available to fulfill injection loads, sea water sourced water treatment facilities are required capable of meeting the total injection load. Providing a capability to treat produced water to a specification suitable for disposal by injection, compared to treating for discharge to sea, is considered an unnecessary complication. Further, sea water/produced water mixing may give rise to compatibility problems which may only be defined by detailed investigation. Since disposal of produced water overboard may be viewed as a pollution risk, conventional water clean-up system requirements for offshore use are discussed in Section 4.1.4 to demonstrate that acceptable discharge specifications can be achieved and reliably maintained. Thus, the principle of treating produced water for overboard discharge at each individual production centre has been adopted, with injection water being sourced from sea water throughout the life of the Field.

Water injection facilities would be similar on both Avalon North and Avalon South, the two centres combined meeting the total Field demand. Availability of water for injection purposes may be maximized through the inclusion of injection water transfer lines between Avalon North and Avalon South, these lines being manifolded at the seabed. Further, feeder lines may be run to the Hibernia zone Riser Manifold Bases to enable any production wells which "water-out" to be used as injectors, if desired.

Gas off the production separators would be transferred to Hibernia South, after gas offtake for fuel and other gas usage at each production centre.

This development approach will be marginally less effective than installing four independent production centres, but will involve less cost and a more equitable distribution of equipment load/space between platforms. Essentially, two trains of water injection facilities are available in the adopted concept and concentration of gas compression equipment enables a reasonable sparing philosophy to be adopted (say, 2 + 1). The overall availability of the entire system is therefore expected to be good within the normal limits of offshore process systems availability, typically 90% to 95%.

Total shutdown of Hibernia South will prevent gas re-injection or export taking place. If flaring can be permitted for short periods then oil production need not be totally halted, at least from the Avalon zones where produced gas quantities are relatively low.

Further, the approach as adopted has advantages for phased development of the Field, permitting the Avalon zones to be produced initially with reduced facilities requirements and moderate flaring levels (assuming gas re-injection is not essential for reservoir management in the Avalon zone).

As a result of the above considerations, the basis adopted for conceptual process flow scheme design, and topside facilities in general, for each individual production centre, is given in Table 4-1 (in Annual Average terms).

4.1.2 Process Flow Philosophy

.1 General

It has not been possible, in the course of this brief preliminary investigation, to carry out computer simulation/optimization analyses of the alternative process flow schemes which may be considered. This has particular relevance for schemes producing gas as well as stabilized crude for tanker export due to the complications of handling natural gas liquids (NGL) fractions. Further, information available to the Study did not provide a meaningful basis for carrying out such computer analyses, particularly on a Field average basis. For the purposes of this Study, however, such detailed evaluation is not considered necessary in developing a reasonable production scenario against which to evaluate gas production and transmission. The scenario adopted is based on knowledge of existing development offshore and applying engineering judgment to the application required for Hibernia.

Due to the importance of NGL's as a valuable product to the development, the alternative means of handling NGL, and its disposal, are discussed in Section 4.2.

TABLE 4-1 BASIS ADOPTED FOR CONCEPTUAL PROCESS FLOW SCHEMES

HIBERNIA FIELD DEVELOPMENT

PRODUCTION CENTRE FUNCTIONAL REQUIREMENTS

	Production Centre			
	Avalon		Hibernia	
Function	North	South	North	South
Oil Production, BOPD	50,000	90,000	50,000	90,000
Gas Production, MMSCFD	20	30	100	30
Water Injection, BWPD	150,000	150,000	-	
Gas Injection/Export, MMSCCFD	-	-	-	
Produced Water Treatment, BWPD	5,000	35,000	5,000	35,000

Notes: 1. All Data Is In Annual Average Terms.

2. Due To Functional Distribution, Water And Gas Injection Quantities Given By Production Centre Should Not Be Assumed Similarly Distributed Within The Reservoir.

3. Gas Production Is Assumed To Arise After Deduction Of Fuel Gas.

4. It Should Be Noted That The Above Requirements May Not Be Representative Of Actual Field Conditions Which May Obtain (Refer To Section 3.1.3).

5. Production At Each Centre May Derive From A Combination Of Well Targets In Both The Avalon And The Hibernia Zones.

The process flow scheme philosophy adopted for Study purposes is illustrated in Figure 4-1.

Due to the installation of facilities on floating platforms with limited deck load/space capability, the process philosophy has been maintained as simple as possible. Of critical importance is the need to produce "dead" crude (e.g., 14 RVP or less) suitable for tanker export. Three or four stages of separation will therefore be required depending on separator inlet pressure.

The inclusion of an oil pipeline export system in the concept would radically alter the philosophy adopted due to the potential for "spiking" NGL's into a high vapour pressure liquids line.

.2 Oil/Gas Separation

The oil and produced water rates at each production centre can be handled by a single train of processing. During subsequent basic engineering of the facilities, if platform weight limitations are not restrictive, dual trains should be considered for both Avalon and Hibernia South due to their higher production rates. Further, the number of stages of separation and their respective operating pressures and temperatures will need to be optimized with respect to minimizing flaring, maximizing oil and/or gas recovery and minimizing compressor capital and running costs. The pressures given in Figure 4-1 are indicative only and cannot be considered optimum at this time. Such optimization will require significant process engineering effort and computer simulation/optimization during basic engineering, given detailed specification for offshore oil/gas/NGL products, their disposal and required landed, onshore specification.

Test separation is assumed to be carried out at each production centre. Centralized testing for each reservoir zone may warrant investigation during basic engineering depending on operator preference.

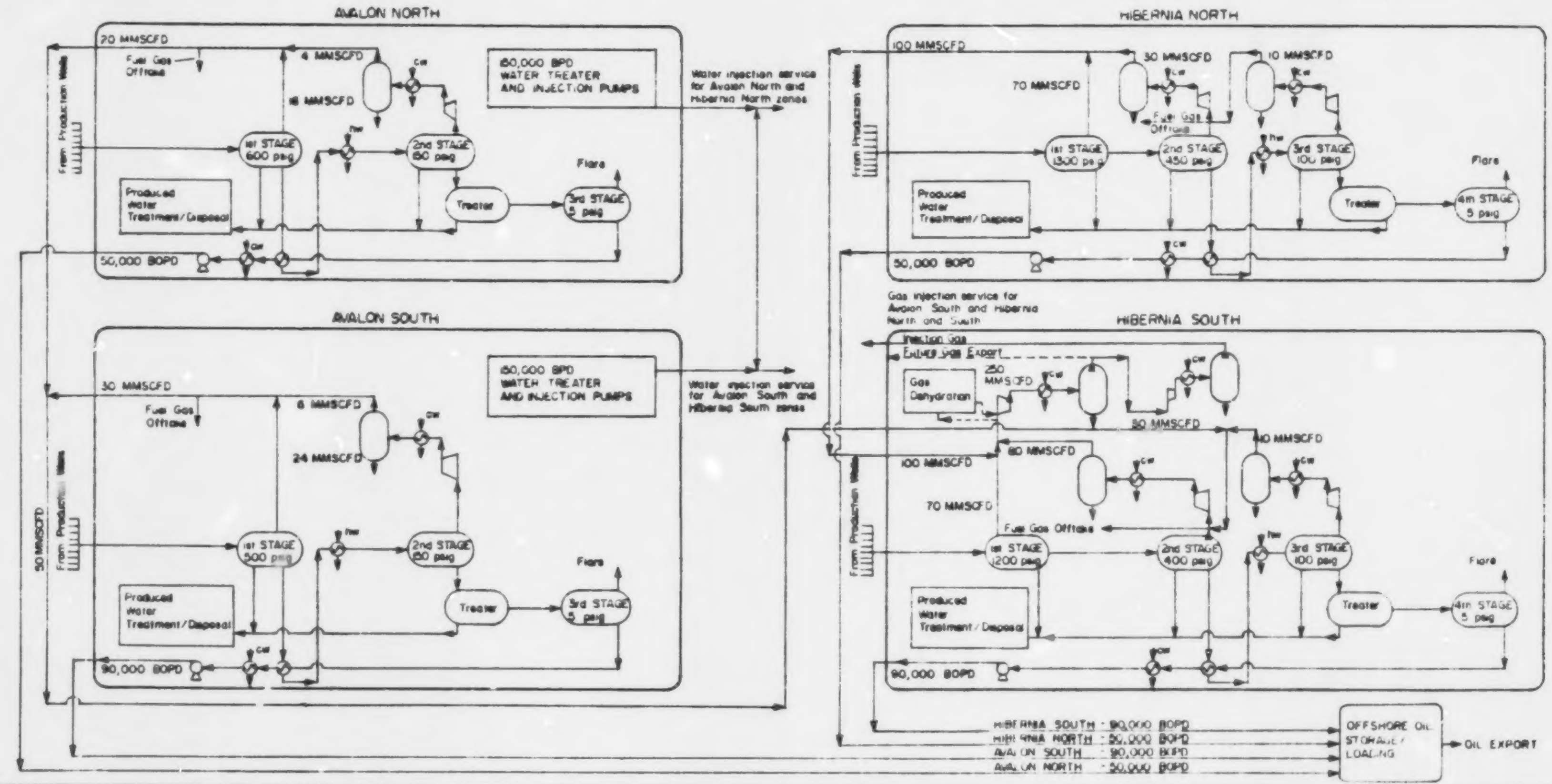
The final stabilized oil product is achieved by atmospheric separation followed by back exchange, cooling and pumping to storage for offshore loading.

The Avalon North and Hibernia North first stage separators and medium pressure gas compressors are assumed to operate, say, 100 psi above the first stage separator pressure of their respective southern platforms in order to allow some pressure drop in the gas transfer lines between the platforms. The Avalon South first stage separator and medium pressure gas compressor are assumed to operate, say, 100 psi above the second stage separator pressure at Hibernia South, again to allow some pressure drop in the gas transfer line. Avalon North and South gas may be commingled at the Avalon South Riser Manifold Base.

.3 Medium Pressure Gas Transfer

Assuming most of the gas at Hibernia South would be produced off the first stage separator, the second stage pressure may be set at, say, 400 psi, to obtain a reasonable compression ratio on the medium pressure gas compressor, say 3:1. This would mean that gas transferred from Avalon North and South would need to be generated at no more than, say, 600 psi. Given the relatively small amount of gas available from these two production centres, it is not expected to be economic to operate at a higher first stage separator pressure at Avalon North and South.

HIBERNIA FIELD - PRODUCTION SYSTEMS CONCEPTUAL DESIGN PHILOSOPHY


AVALON NORTH
20 MMSCFD
Fuel Gas Offtake
4 MMSCFD
16 MMSCFD
cw
hw
From Production Wells
1st STAGE 600 psig
2nd STAGE 150 psig
Treater
3rd STAGE 5 psig
Flare
Produced Water Treatment/Disposal
50,000 BOPD
150,000 BPD WATER TREATER AND INJECTION PUMPS
Water injection service for Avalon North and Hibernia North zones
AVALON SOUTH
30 MMSCFD
Fuel Gas Offtake
6 MMSCFD
24 MMSCFD
50 MMSCFD
1st STAGE 500 psig
2nd STAGE 150 psig
Treater
3rd STAGE 5 psig
Flare
Produced Water Treatment/Disposal
90,000 BOPD
150,000 BPD WATER TREATER AND INJECTION PUMPS
Water injection service for Avalon South and Hibernia South zones
HIBERNIA NORTH
100 MMSCFD
70 MMSCFD
30 MMSCFD
10 MMSCFD
Fuel Gas Offtake
1st STAGE 1300 psig
2nd STAGE 450 psig
3rd STAGE 100 psig
Treater
4th STAGE 5 psig
Flare
Produced Water Treatment/Disposal
50,000 BOPD
Gas injection service for Avalon South and Hibernia North and South
HIBERNIA SOUTH
Injection Gas
Future Gas Export
Gas Dehydration
250 MMSCFD
80 MMSCFD
50 MMSCFD
40 MMSCFD
100 MMSCFD
70 MMSCFD
Fuel Gas Offtake
1st STAGE 1200 psig
2nd STAGE 400 psig
3rd STAGE 100 psig
Treater
4th STAGE 5 psig
Flare
Produced Water Treatment/Disposal
90,000 BOPD
HIBERNIA SOUTH - 90,000 BOPD
HIBERNIA NORTH - 50,000 BOPD
AVALON SOUTH - 90,000 BOPD
AVALON NORTH - 50,000 BOPD
OFFSHORE OIL STORAGE/LOADING
OIL EXPORT

NOTES: The disposal of condensate from the compressor knock-out vessels is not indicated due to insufficient definition of optimum method of handling at this time. Refer text for discussion of alternatives

Production Separators

Compressor Knock Out Vessels

cw - Cooling water
hw - Heating water

JSI 1/7575

Figure 4-1

When medium pressure separator off-gas is transferred from platform to platform it may condense hydrocarbons, will certainly condense water vapour and would probably enter the hydrate formation region. This may be overcome by either:

- methanol injection;
- prior dehydration;
- transfer line insulation; and/or
- maintaining flowing temperature above the hydrate formation temperature by means of trace or wall effect heating.

Line heating is attractive for the short in-field transfer lines since it reduces topsides weight and space requirements and eliminates continuous use of methanol (although this will still be required for start-up and emergency situations). Sufficient line insulation should be achievable through burial of the lines.

.4 Gas Compression for Injection/Export

Given the range of reservoir pressures anticipated, i.e., approximately 3,600 psi for Avalon and 5,900 psi for Hibernia, and the requirement to transfer injection gas at high pressure from Hibernia South to Avalon South, the discharge pressure of the gas injection compressors is envisaged to be in the order of 6,000 psi. Typically then, the requirement may be met using a two-stage centrifugal machine from say 1,200 psi to 2,700 psi interstage and 6,000 psi discharge with interstage cooling and liquid knock-out. The interstage pressure of 2,700 psi would be used for sales gas export if required. For reliability and flexibility it is recommended that two working and one spare train of injection compressors is considered. Gas dehydration is not considered necessary for injection purposes (but is required for export) (refer to Section 4.4).

.5 Water Injection

Two 150,000 BWPD units would be designed, identical for spares, maintenance, etc., one each being installed on Avalon North and South.

.6 Produced Water

It is anticipated that, given the 3 or 4 stages of separation, a water specification of 3% BS&W in oil is possible, depending on produced fluid characteristics. However, given the API gravity range and fluid analyses available to the Study, which show the presence of several percent napthenes, emulsions may be produced which at this time it is impossible to predict whether chemicals could adequately break. An electrostatic treater is therefore recommended in each oil train.

The electrostatic treater will probably be more effective if the oil is heated. In the process scheme therefore the oil is back exchanged with "dead" crude from the atmospheric separator and then heated further before flashing in the low pressure separator. The oil then flows directly through the electrostatic treater where the water (and, if needed, salt) specification is achieved.

.7 Fuel Gas System

The principal source of gas to the fuel gas system will be from a suitable offtake point at a pressure in the 300 psi to 600 psi range (refer to Figure 4-1). An alternative fuel source will also be required for emergency or shutdown usage, e.g., diesel.

Two pressure levels are normally required for the platform utility users; a high pressure source and a low pressure source.

Normally, separator gas (ca. 300 - 600 psi) is let down to provide gas up to 200 psi for such uses as the gas turbines for compression and power generation and possible pressurization of the hot water system (if hot water is the heating medium). This source is termed the HP source. Further let-down of the HP fuel gas will provide a low pressure source (up to 50 psi). This system supplies the other platform uses such as inert gas generators, flare pilots, hot water heaters and deaerators for water injection purposes.

During normal operation of the platform, fuel gas supplied from the high pressure offtake is heated in the fuel gas preheater prior to pressure let down across a control valve. Heating may be required in order to avoid cold conditions downstream of the valve. The gas at 200 psi to 250 psi enters the higher pressure fuel gas knock out drum where any condensates formed during let-down are removed, although during normal operation the drum will run dry. From this drum the fuel gas is superheated in the HP fuel gas heater prior to entering the high and low pressure distribution systems.

Gas for the higher pressure distribution system is filtered in cartridge type units and then distributed to the various HP users as defined earlier. For the low pressure system, the gas is let down to 50 to 100 psi across a control valve and fed to the low pressure fuel gas knock out drum. Although normally a dry drum, this vessel provides the final opportunity for liquid removal prior to distribution to the LP users.

During emergency periods, when production is down, the alternative source of diesel oil can be used. This is to enable the essential utilities for life support, etc., to be capable of running. Additionally, a back up source of fuel gas in case of low throughputs or fuel gas system malfunction may require that pipeline gas from another source be made available. At low production throughputs at Avalon North and South, if the water injection rates are maintained, the consumption of fuel gas is relatively high and these production centres may become gas deficient. In this case, the direction of flow in the medium pressure gas transfer lines to Hibernia South may need to be reversed.

Expected changes in the composition of the gas between alternative sources (e.g., the calorific value, S.G.) should be checked to ensure no turbine problems arise as the source of gas is changed from one part of the process to the other.

Turbine manufacturers will place limitations on calorific value, etc. The calorific value of the gas should, according to turbine manufacturers, be held to within 3% of the value used when setting up the fuel ratio value. A difference greater than this value may lead to difficulties with generator synchronization when switching from liquid to gas.

.8 High Water/Oil Ratio Wells

During the life of the Field productivity difficulties may arise with high water/oil ratio wells. Information available to the Study indicates that wells will be shut-in when the Water/Oil Ratio reaches 2:1.

One alternative which has been suggested for handling such wells is to feed all low WOR wells to a high pressure initial stage of separation, operating 2 phase, with fluids (oil/water) passing to an intermediate second stage, which is a 3 phase vessel, and to which high WOR wells are produced directly without passing through the high pressure stage. It is considered that such a system is feasible, its application depending on detailed study. However, should a high proportion of gas be co-produced with the high water cut then any gas by-passing the high pressure separator increases the cost of compression.

A more desirable principle of operation, however, is to simplify the production train allowing all vessels to operate 3 phase removing up to 75% of incoming water in the first stage with very little effect on the separator residence time. This ensures that the dehydration facilities are not made unecessarily large. Additionally, elimination of produced water at each stage of separation reduces the complications that arise with emulsion effects from throttling.

In essence, the design pressures of the production train are determined from detailed investigations which include the effect of water production both by well and by field from initial to final predicted levels of water cut. Significant water cut later in the life of the field may require a reduction in separator operating pressures. The indicative pressures given in Figure 4-1 may change as a result of more detailed study.

4.2 NGL UTILIZATION

4.2.1 Introduction

Significant engineering effort, involving multiple sub-studies and considerable computer simulation/optimization, is necessary to define the optimum process scheme. This is particularly true with regard to establishing the extent of Natural Gas Liquids which may be exported either with the oil or with the gas or not at all. The difficulty is compounded by the use of oil export by tanker loading where strict and low RVP's obtain. The simplest analytical case arises where both a gas and an oil pipeline are available. Consideration of the proportions of NGL transmitted with either product also depends on the economics of utilization at the respective landfalls.

This preliminary investigation can only therefore present the alternatives for NGL utilization and draw general conclusions with respect to Hibernia, since the basic engineering effort required is beyond the scope of this Study and cannot at this time be based on full information. For this reason, NGL utilization is not defined within the process scheme illustrated in Figure 4-1 (e.g., disposal of knock-out vessel bottoms).

4.2.2 Discussion

The following objectives apply to the Hibernia development:

i) Stabilized crude oil export by tanker;
ii) Gas export by pipeline;

iii) Optimization of compression requirements;
iv) Minimization of flaring.

In the absence of a gas pipeline, or some other form of gas export method, the quantities of stabilized liquids exported should be optimized. With the inclusion of a gas pipeline, optimum liquids export may remain the objective followed by export of maximized quantities of gas.

If the landed gas specification calls for a "dry" gas, it is likely that a third liquid product (NGL) will arise requiring an alternative disposal route. If significant quantities of NGL arise, a separate export system may be economic, e.g., pipeline or tanker loading. With tanker loading of NGL's produced at a relatively low rate, storage in separate deck tanks on the oil storage vessel may be envisaged with transhipment by LPG carrier. This will result in a complex marine operations situation.

Where the landed gas specification is less strict (as is assumed in this Study) increased quantities of NGL may be transported in the gas pipeline up to the specified limits of hydrocarbon dewpoint, calorific value, etc. Where offshore processing is essentially being replaced by onshore processing of the gas stream, "dense phase" or two phase gas transmission may be considered thereby maximizing the opportunity to export NGL's in the gas pipeline. As defined in Section 4.4, "dense phase" gas transmission has been adopted for Study purposes, two phase flow being too unpredictable and inefficient over the distances considered.

The quantity of NGL's not exported either in the oil or in the "dense phase" gas transmission system is anticipated to be small and their preferential utilization for fuel may be considered. Within the context of the Hibernia development the decision must be made whether to still maximize stabilized crude oil liquids exported.

This reduces to an economic evaluation relating relative NGL worth at the respective landfalls for oil or gas, compared to the additional equipment required offshore to maximize NGL's spiked into the crude.

4.2.3 Methods of Increasing Crude Oil Recovery

It should be recognized that the net requirements for the stabilization of unstabilized crude oils vary depending upon whether fluids are straight from the wellhead or are cold and partially stabilized and whether the stabilization is carried out offshore or onshore. Methods used onshore are not directly transferrable to the offshore situation particularly where floating platforms are utilized.

Of all possible methods, stagewise stabilization offers a relatively cheap, simple method of processing. The conditions on stabilization can be varied to suit whether the emphasis is on maximizing crude oil production or maximizing NGL recovery. However, stagewise stabilization offers little selectivity in terms of separation amongst the various constituents of unstabilized crude oil.

The following "enhancements" may be applied to the basic separation process to improve crude recovery:

i) Flash gas is processed for condensate recovery and condensate reinjected into the crude and allowed to flash down successively with the crude;

ii) Flash gas from each stage is compressed and re-injected into the next higher stage. Thereby some of the constituents of the flash gas condense against the incoming crude;

iii) Flash gas from selective stages is processed and fractionated in a column, the fractionated product being re-injected into the crude and allowed to flash down successively with the crude.

Each of these schemes involves a higher compression requirement than would otherwise arise with straight stabilization and disposal of flash gas. Further, while the quantities of NGL arising as a third product are reduced, the third product is not wholly utilized. The fractionation column is, however, the most selective and may recover virtually all butanes and a significant proportion of the propanes.

The three schemes will normally achieve the following increases in crude recovery on a mass basis:

Scheme	Increased Crude Recovery
i)	5%
ii)	0.8% to 1.5%
iii)	1.5% to 1.7%

Scheme (i) offers the highest increase in crude recovery and was used in the Thistle Field process scheme in the North Sea. The only known example of a flash gas fractionation column offshore is in the Brae Field where an extremely complex process scheme is used. The concept of using a column on a floating platform does not appear attractive at this time but during basic engineering all alternatives for NGL utilization should be considered.

4.2.4 Typical Existing Applications

The following existing North Sea applications provide an illustration of what is typical practice offshore.

.1 Brent and Ninian Fields (UK Sector, North Sea)
Flaring is considered unacceptable, excess gas being re-injected until FLAGS pipeline to St. Fergus fully operational. Associated gas from the fields may be transported to shore either in the oil pipeline to Sullom Voe or with the gas to St. Fergus in the FLAGS pipeline. Based on the production of 400,000 BPD, 13 RVP crude production, three levels of liquids product vapour pressure yield the following gas quantities at the respective locations:

Vapour Pressure in the Oil Pipeline	Pipeline Termination	
	Sullom Voe	St. Fergus
38.4 psia	25 MMSCFD	72 MMSCFD
90 psia	38 MMSCFD	59 MMSCFD
505 psia	97 MMSCFD	NIL

(All excluding 23 MMSCFD fuel gas)

Surplus condensate is injected into the crude stream thus delivering partially stabilized crude to Sullom Voe.

.2 Tartan (UK Sector, North Sea)
It is understood that both NGL injection to the reservoir and/or spiking into the crude line is available thus delivering partially stabilized crude to Flotta.

.3 Tyra et al (Danish Sector, North Sea)
Condensate (20,000 BPD) separated and stabilized in 3-stage flash system to produce 100 RVP product for pipeline to shore or 4-stage flash system to produce 12 RVP product for tanker loading.

.4 Thistle (UK Sector, North Sea)
Prior to commissioning of oil pipeline to Sullom Voe, crude exported by tanker loading. Processing facilities designed to produce low RVP crude. NGL's produced are returned to the second stage of separation. Further, NGL's from the high pressure gas compression after-separator are let down into a fuel gas knock-out drum for fuel requirements. Condensates from the low and intermediate gas compression after-separators are commingled prior to injecting into the second stage separator.

4.2.5 Application to Hibernia

Basic engineering of the Hibernia process scheme will require significant attention to NGL utilization. For example, the Tyra gas/condensate facilities design included 36 alternative basic cases with respect to the overall system to determine the preferred/optimum/operable design. These cases were reduced through feasibility studies and basic engineering to 12 cases for detailed design progression.

For the Hibernia Field which involves floating platforms and multiple production centres in an extreme environment, simplicity of design will be essential to maintain efficiency and operability. NGL utilization must also be simple and the disposal of the small amounts of NGL likely to arise, given the overall design philosophy, would most likely be disposed of by a combination of the following alternatives:

- i) Use as fuel gas;
- ii) Re-injection into process stream;
- iii) Re-injection with gas into the reservoir;
- iv) Flaring (minimum).

The above simple approach is also likely to lead to the minimization of NGL facilities with the maximum NGL utilization for this type of field development.

4.3 PRODUCED WATER TREATMENT FACILITIES

4.3.1 Introduction

The basic data available to the Study provides an indication of the following throughputs of produced water from each area:

	Avalon		Hibernia	
	North	South	North	South
Produced Water (BPD)	5,000	35,000	5,000	35,000

The water cut will vary over the life of the Field. Assuming that the above are maximum the produced water treatment facilities may be as described below.

Waste water can refer to either one or a combination of the following:

i) Produced water (may contain solids and sand) associated with crude or gas.

ii) Slopwater - Open or closed drain system is the source, which includes oil contaminated rainwater, water used to washdown decks, clean out equipment, etc.

iii) Deballast Water - Water displaced from subsea oil storage tanks by incoming oil or ballast water pumped out of a tanker where segregated ballast systems are not used.

Environmental regulations will stipulate the quality of water discharged overboard, and hence condition the design specification of a clean-up system.

4.3.2 Controls on Discharges from Platforms

In offshore applications in the North Sea and elsewhere, operators are normally required to maintain the oil content of any water discharge to sea below an average of 40 to 50 ppm and below 100 ppm for 96% of the time. Large platforms capable of discharges in excess of 100,000 BPD are required to maintain an average oil content below 40 ppm. Smaller platforms (the case applies here) are required to maintain oil content below 50 ppm.

For design purposes, a level of 5-20 ppm should be aimed for. Current trend is towards a residual of 15 ppm in discharge.

Should the wellstream contain sand (not defined for this particular application) it will be necessary to consider removal and washing of solids from the produced water.

4.3.3 A Typical Produced Water Treatment System

Below is described a typical produced water treatment system that can be applied to all the platforms in the Hibernia Study based on the assumption that similar specifications apply.

For each production centre, based on the throughputs suggested earlier (refer to Section 4.3.1), the produced treatment system inlet water specification is typically taken to have an oil concentration of 3% by volume (maximum). The reason for taking this high inlet oil concentration in practical terms is that although three phase separators are designed for oil in water outlet specification of 1000 ppm, during surge conditions or water break out conditions or separator guarantees not performing, a contingency has to be applied.

Produced water from the oil/gas/water separators are let down and fed via a collection header to the produced water flash drum (5 psig operating) where any evolved gases can be removed and sent to flare. After degassing, the produced water is fed to an oil/water separator, where primary oil separation occurs. Large globules of oil are recovered from the water and returned to the production system. The produced water from the oily water separators, now with a lower oil concentration, is fed to an induced gas flotation unit which performs a polishing function. Small globules of oil are floated to the surface, promoted by gas induction, and mechanically skimmed off. The float, which forms 10% of the flotation unit throughput, is recycled to the oily water separators for further treatment.

Prior to the discharge of the treated sea water to the drains or production caisson, the effluent quality is analyzed to ensure that the discharge specification is achieved.

4.3.4 Oil Removal Processes and Comparative Effectiveness

Separation processes which may be applicable fall into two categories:

- Gravity separation devices of which the various designs of plate separator are the most compact and efficient; and
- Polishing processes such as flotation, filtration and coalescence, of which the only option with any trade record is induced gas flotation.

Because of the characteristics of produced water, neither a plate separator nor an induced gas flotation unit on its own would reliably and consistently produce the desired effluent quality. The use of a two stage system is therefore recommended. This also provides the additional feature of operational flexibility. For example, the effluent quality is expected to be within specification with one of the flotation unit motors out of operation, or for a short period, with one of the plate separators offline.

Corrugated Plate Interceptors are suitable when inlet oil concentrations are high, e.g., 3000 ppm. Effluent concentration can be as low as 50-100 ppm. Gas flotation systems, which do not work effectively with high inlet oil levels, are more suitable for treating low inlet concentrations of 200-300 ppm, producing very low outlet concentrations of 10 to 15 ppm. At 1000 ppm inlet a flotation system outlet concentration rises to 50 ppm approximately (even with chemical injection). Hence it is advisable, with a floating system to install an oil skimmer tank upstream.

4.3.5 Caissons

The discharges of oily effluents is usually carried out via a sealed vented caisson for safety and ecological reasons. The caisson is vented to a safe location. Clean discharges would be routed to a separate caisson. Any accidental leakage of oil is trapped on the surface of the water in the caisson and can be skimmed off by a caisson pump before the contamination reaches the sea.

A production platform will usually have several disposal caissons. Platform discharges overboard will usually be split as follows:

* All clean discharges, e.g., sand filter backwash, seawater system drains;

- Possibly oily discharges, e.g., oil/water separators;
- Drilling fluids: chippings through drill rig drains.

The oil discharges and drilling caissons incorporate submersible caisson pumps to pump separated oil to the platform for recovery.

4.3.6 Application to the Hibernia Complex

The Avalon North and Hibernia North produced water throughputs indicate the use of a similar unit and the Avalon South and Hibernia South throughputs indicate the use of a similar unit.

It must be emphasized that, due to the presence of a treater unit at each facility, it may be necessary to dehydrate with sea water (as the wash water medium) and this capacity must be added to the produced water capacity in specifying the unit size. If the sea water is used, depending on the amount of wash water requirements, compatibility of sea water and produced water needs to be thoroughly reviewed.

4.4 GAS PIPELINE CONCEPTUAL OPERATING PHILOSOPHY

4.4.1 General

Depending on the characteristics of the produced wellstream fluids and the landed gas specification required, the operator will need to decide a design philosophy by selecting a flow regime from the following alternatives:

i) Single phase "dry" gas
ii) "Dense phase" "rich" gas
iii) Two phase gas/liquids.

Single phase "dry" gas transmission systems operate in the gas vapour phase such that there will be no liquid drop out at the lowest operating temperature and pressure (refer to Figure 4-2). Where the product gas is "rich" (i.e., containing significant hydrocarbon heavy ends), the offshore treatment equipment to remove the Natural Gas Liquids (NGL) is expensive and an alternative disposal route for the NGLs is required, e.g., fuel usage, "spiking" into a crude oil pipeline, separate pipeline, re-injection or flaring.

Two phase flow is undesirable for long pipelines since throughput capacity for a given pipe diameter is reduced, flow behaviour cannot be accurately predicted, sphering costs will be high and variability in liquid slug size and arrival frequency will create major operating problems. However, economic considerations may support the selection of two phase flow in order to avoid high line pressure. There are examples of two phase flow offshore, however, e.g., in the Campos Basin offshore Brazil.

Dense phase transmission of a "rich" gas requires a high minimum operating pressure for the system to prevent liquid drop-out but increases the quantities of NGL which can be transmitted in the gas line. Offshore processing facilities are therefore less complex, although onshore separation of liquids is required. The concept of "dense phase" transmission is growing in acceptability amongst operators, particularly in the North Sea. The high minimum operating pressure implies that the maximum allowable pressure rating of pipe specified may also be high thereby requiring thick wall pipe. However, the diameter of a pipeline to carry a given flow reduces as the operating pressure is increased.

In addition to the above considerations, the produced wellstream may contain quantities of corrosive elements, e.g., CO_2 and/or H_2S. For small quantities (e.g., a few percent by volume) dehydration of the gas and the use of a corrosion inhibitor may provide a solution, particularly if transmission temperatures are low (with a small increase in the normal corrosion allowance to handle residual corrosion). For higher quantities, removal offshore may be required. Over short distances, the alternative of using corrosion resistant pipe may be considered.

4.4.2 Landed Gas Specification

Knowledge of the required landed gas specification is critical not only for the design of the offshore facilities, as discussed in Section 4.2, but also, by association, for the design of the gas pipeline.

Should gas suitable for direct domestic use be required, then typically, a high quality, "dry" gas specification is demanded by the gas purchaser similar to that required by the British Gas Corporation in the U.K.

TYPICAL NATURAL GAS PHASE ENVELOPE

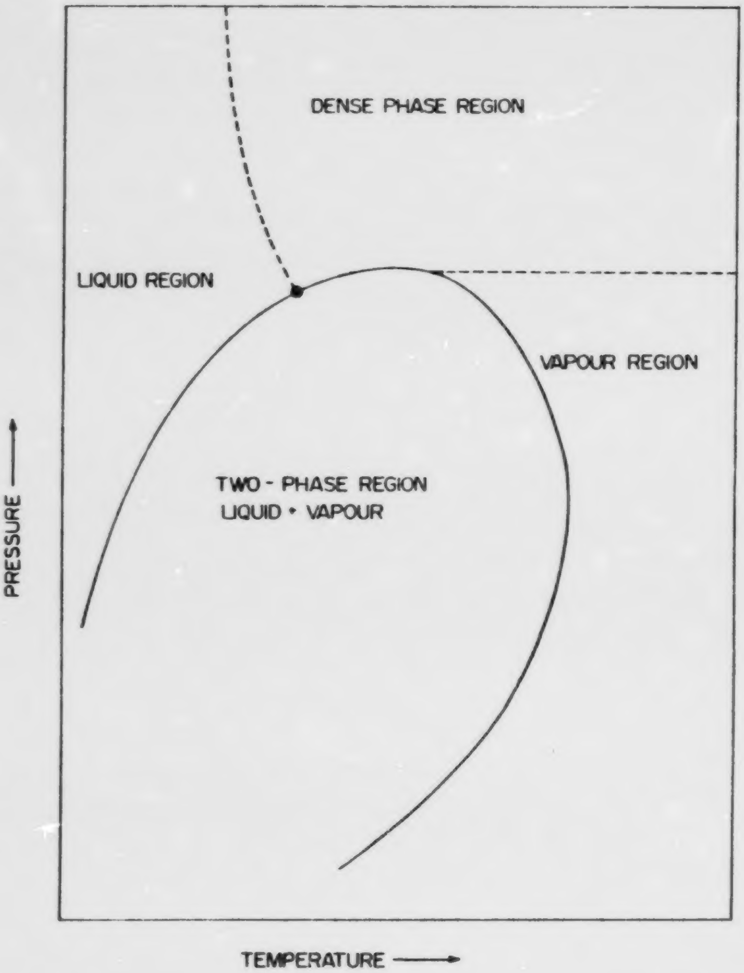

DENSE PHASE REGION
LIQUID REGION
VAPOUR REGION
TWO - PHASE REGION
LIQUID + VAPOUR
PRESSURE ⟶
TEMPERATURE ⟶

Figure 4-2

Typical Target Specification For Natural Gas Quality in Natural Gas Purchase Contracts

Oxygen	: 0.1 mol percent maximum
Carbon Dioxide	: 1.15 mol percent maximum
Hydrogen Sulphide	: 3.3 ppm by volume maximum
Total Sulphur	: 35 ppm by volume maximum
Water Vapour	: 3 lbs/MMSCF maximum
Hydrocarbon Dewpoint	: 28.13°F maximum at any gauge pressure less than 1015 psi
Gross Calorific Value	: 1025 Btu/SCF (dry) minimum 1045 Btu/SCF (dry) maximum
Wobbe Number	: 1400 Btu/SCF (dry) minimum 1270 Btu/SCF (dry) maximum
Temperature	: 58.73°F maximum 40.73°F minimum

The above is a stringent specification to meet offshore for associated gas sources and would normally be achieved at an onshore terminal thus permitting the production offshore and transmission by submarine pipeline of a lower quality gas.

More likely for a typical associated gas sourced pipeline, where liquid drop out is to be avoided, hydrocarbon dewpoint conditioning to 40°F or lower is required for pressures between 2030 psig and 1100 psig.

No end use for Hibernia gas has been indicated for Study purposes. Therefore, adopting the premise of minimizing and simplifying offshore process equipment for the floating production platforms, it has been assumed that a high quality "specification" gas need not be produced offshore. This will also maximize the opportunity for recovery of gas and NGL's.

It is important to note that if a high quality gas is required to be produced offshore then the development plan as adopted for Study purposes will need to be reviewed and revised, and its feasibility re-evaluated.

4.4.3 Pipeline Design Philosophy

In essence then, the pipeline operating philosophy is based on the transmission of a gas which may condense hydrocarbon liquids under certain operating conditions. It remains to decide the extent to which such liquid drop-out can be permitted and the procedures required to handle liquid volumes.

For "dense phase", "rich" gas transmission no liquid drop-out should arise if the gas has a hydrocarbon dewpoint of no more than, say, 100 °F at 1000 psi and the minimum operating pressure of the pipeline is above approximately 1,600 psi. This means that simple cooling, using sea water or air, together with separation of condensed liquids from the gas stream is sufficient to minimize liquid drop-out in the pipeline.

Assuming that there are onshore processing facilities to treat the gas being transmitted from Hibernia, hydrocarbon dewpoint control other than by simple means may or may not be applied offshore depending on available gas composition and considerations of potential liquid drop-out over the length of the pipeline. Typical gas compositions which may arise offshore are as follows overleaf:

Typical Offshore Produced Gas Compositions

Component	Hyd. Dewpoint Control With	Hyd. Dewpoint Control Without	Meter Run Gas (DST)*
N_2	0.60	0.60	0.30
CO_2	0.90	0.90	0.91
C_1	79.90	77.40	85.82
C_2	10.10	10.70	7.24
C_3	5.70	6.70	3.85
C_4	1.90	2.40	1.32
C_5^+	0.90	1.30	0.56
	100.00	100.00	100.00
Mol. Wt.	20.80	21.70	19.34

* Refer to Section 3.1.3.

The above typical compositions do not derive from analysis of the specific Hibernia production process adopted for Study purposes, but arise from knowledge of other offshore field conditions, with the exception of the Field average DST Meter Run Gas which is given as input data to the Study. As an indication of conditions which may arise at Hibernia, the Field average Meter Run Gas composition from Hiernia DST data is given for information and represents a higher quality gas than may be considered for transmission.

Given the above typical gas compositions, and limiting onshore reception pressure to approximately 1000 psi to 1500 psi, the order-of-magnitude quantities of liquid which may drop-out (at a ground temperature of 15°F) are given overleaf:

Potential Liquid Drop-Out (BBL/MMSCF, 15°F)

Pressure	Hyd. Dewpoint Control With	Hyd. Dewpoint Control Without	Meter Run Gas DST
1,500 psig	Negligible, All Cases		
1,000 psig	60	92	21

Pigging of the pipeline will therefore be required to displace liquids. Frequency will be controlled by the reduction in efficiency as liquids build, monitored by the associated reduction in delivery pressure onshore.

Typical, known pigging/sphering applications are as follows:

Case	MMSCFD	DIA.	BBL/MMSCF	Sphering Interval	End Pressure
A	300	20"	65	4 mths.	1160 psig
B	350	24"	3	1 day	1000 psig
C	200	20"	35	3 mths.	840 psig
D	400	36"	60	2 hrs.	400 psig
E	680	32"	1	3 days	750 psig
F	960	36"	8	1 day	NA

Given the above data, and the potential for liquid drop-out listed above, the pigging frequency with or without hydrocarbon dewpoint control is likely to be in the order of once every two to three days or once every day respectively. This does not introduce an onerous operational requirement on the development and limits liquid drop-out to manageable proportions.

Liquid "slug" catching facilities will need to be provided at the onshore gas reception terminal, sized operationally, depending on the Bbl/MMSCFD drop-out rate, e.g., 7,500 Bbls capacity for 250 MMSCFD at 30 Bbl/MMSCF with daily sphering.

For Study purposes, it has been assumed that the pigging/sphering frequency without hydrocarbon dewpoint control is acceptable and thus no hydrocarbon dewpoint control facilities are included on the Hibernia South topsides.

Given the gas injection compression arrangements discussed in Section 4.1, the peak available inlet pressure to the pipeline has been assumed as 2,700 psig. It is recognized that this is a high pressure compared to conventional pipeline systems but is in keeping with current designs for "dense phase" gas transmission systems offshore. The minimum operating pressure range of 2,700 psig inlet to 1,500 psig outlet in the "just pigged" condition with minimum residual liquids remaining in the line is considered acceptable for application to Hibernia. As liquids build up in the line, the outlet pressure will reduce and the line would again be pigged. An operational margin of, say, 300 psi below 1,500 psig has been allowed on arrival pressure to allow for pressure drop due to liquid build-up.

A turndown figure of 10:1 on throughput has been assumed at this time for any pipeline calculations carried out.

The design philosophy as adopted for Study purposes results in a flexible, operable system with a number of benefits:

- offshore equipment requirements are minimal; the compression equipment installed for gas injection purposes can be utilized for gas export;

- the high operating pressure reduces the pressure drop in the line thus permitting a smaller line diameter for a given flowrate;
- the formation of liquids in the line by retrograde condensation is limited above 1,500 psig thus reducing the requirement for pigging;
- an operational margin of 300 psig to cater for formation of liquids in the pipeline may be allowed without restricting the throughput.

Finally, the system has considerable flexibility as regards to transport of additional gas from other sources outside Hibernia.

SECTION 5

FLOATING PRODUCTION FACILITIES

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5.0 FLOATING PRODUCTION FACILITIES

5.1 INTRODUCTION

Consideration has been given to the overall development facilities required for Hibernia in addition to those strictly required for gas production and transmission. This has been done in order to:

i) Ensure that the facilities required for gas transmission are an integrated part of the overall development and not simply added "piecemeal";

ii) Place gas transmission requirements in perspective within the overall development in terms of:

- * Relative technical feasibility
- * Incremental facilities requirements
- * Relative cost differentials

The technical definition of the Floating Production Facilities adopted for Study purposes is not the result of detailed comparison and evaluation of the alternatives and to this extent should not be assumed to represent a preferred approach at this time. The principal objective in including this technical definition is to develop a reasonable basis for the assessment of indicative overall development schedules and costs.

The overall development plan adopted for Study purposes is described in Section 3.4. This Section briefly presents the general requirements for the key components of that development plan other than the gas transmission system which is dealt with in greater depth in Section 7.

The principal components are as follows:

- Topsides Facilities
- Semi-Submersible Support Structures
- Subsea Systems and Risers
- In-Field Flowlines and Transfer Lines
- Crude Oil Storage System

The construction and installation of the above facilities, in addition to the gas transmission system and onshore facilities, will be a major task. This aspect is also discussed below since the construction and installation of the gas transmission system must be scheduled within the overall development plan and may or may not be a critical activity depending on the overall programme.

5.2 TOPSIDE FACILITIES

5.2.1 General

The topside facilities required for each semi-submersible floating production facility (FPF) include all items associated with the FPF as a marine vessel, including:

- General and Marine Equipment;
- Mooring Equipment;

as well as all items associated with the production function, including:

- Oil Production Equipment
- Gas Handling Equipment
- Utilities
- Water Injection Equipment (Avalon North and South only)
- Gas Injection/Export Equipment (Hibernia South only)
- Accommodation
- Helideck
- Flaring Equipment
- Bulks (Inst./Control, HVAC, etc.)

In addition to the main hull deck structure which is included in the support structure allowance (refer to Section 5.3) local structural steelwork will be required for equipment support and skidding.

Also, although conventional drilling/workover facilities are not included, a certain amount of well control/TFL equipment will be required and a production riser handling system and diving spread is necessary.

5.2.2 Marine Systems

Marine systems on a semi-submersible drilling rig include not only mooring equipment, thrusters, etc., but also accommodation, HVAC, utilities, etc. Such latter systems will be shared by both marine and production functions on the FPF.

Marine equipment not having a shared production function may amount to approximately 1,500 tons to 2,000 tons at the operating draft with the mooring cables out. This assumes a conventional mooring system with deck winches. Equipment weight may be reduced by the application of a purpose-designed mooring system involving no winches, cable/chain storage, etc., based on pulling in a prelaid mooring spread.

A vertical mooring load of several hundred tons will be imposed on location, say 300 tons.

5.2.3 Production and Associated Systems

In accordance with the conceptual process flow philosophy defined in Section 4.1.2, an order-of-magnitude weight estimate for the main production and associated systems is given in Table 5-1. The weight areas specified in Table 5-1 are defined as follows:

- Oil/Gas Separation
- Product Oil Pumping
- Intermediate Gas Compression
- Export Gas Dehydration
- Injection/Export Gas Compression
- Metering/Pigging
- Produced Water Treatment

  - Sea Water System
  - Fire Water System
  - Water Injection
  - Power Generation (Central/Emergency)
  - Fuel Gas System
  - Flare Gas System
  - Inert Gas System
  - Instrument Air System
  - Cooling Medium Systems
  - Heating Medium Systems
  - Potable Water System
  - Diesel Oil System
  - Chemical Injection System
  - Closed/Open Drains
  - Miscellaneous

* Accommodation and Hotel Services (100 beds assumed)
* Helideck (including fuel system, helicopter)
* Flare Tower/Booms
* Structural Steel (50% wet equipment weight)
* Bulks
  - Telecommunications
  - Electrical Systems
  - Pipework, Valves and Fittings
  - Instrumentation and Panels
  - Workshop and General Stores
  - Cranes
  - Lifeboats
  - Heating, Ventilation and Air Conditioning (HVAC)
  - Control Rooms, Offices, and Fittings
  - Miscellaneous

Since only a very general weight assessment can be made at this time, a contingency of 30% has been allowed.

TABLE 5-1 TOPSIDES WEIGHT SUMMARY

HIBERNIA GAS PRODUCTION STUDY

(All Weights in Long Tons)

	Avalon North		Avalon South		Hibernia North		Hibernia South	
	Dry	Operating	Dry	Operating	Dry	Operating	Dry	Operating
1. Production Equipment and Main Utilities	1,300	2,240	1,530	2,670	1,300	2,110	1,950	2,850
2. Accommodation and Hotel Services	500	500	500	500	500	500	500	500
3. Helideck	220	240	220	240	220	240	220	240
4. Flare Tower	250	250	270	270	350	350	390	390
5. Structural Steel	1,120	1,120	1,340	1,340	1,060	1,060	1,430	1,430
6. Bulks	1,180	1,380	1,280	1,480	1,180	1,380	1,720	1,970
Sub-Total	4,750	5,730	5,140	6,500	4,610	5,640	6,210	7,380
7. Contingency (30%)	1,370	1,720	1,540	1,950	1,380	1,690	1,860	2,210
TOTAL	5,940	7,450	6,680	8,450	5,990	7,330	8,070	9,590

5.2.4 Riser Handling System

The integral riser would be handled through a moon-pool in the centre of the rig deck. A purpose built riser handling system with a high degree of automation is likely to be specified. Such a system would include space to "set-back" the riser when pulled and may weigh in the order of 150 tons, including:

- Gantry Crane
- Work Platforms and Spider Deck
- Guide Rails
- Set-Back System

It is estimated that with the riser in position, a top tension in the order of, say, 240 tons may be required (tensioners rated at 360 tons). This will exceed the weight of the riser when set back which is expected to be in the order of 100 tons, depending on functional design, including riser head and bottom assemblies. The worst load case for the FPF will therefore be with the riser in position resulting in a total weight allowance in the riser area of, say, 390 tons.

A diving spread will weigh in the order of 150 tons.

5.2.5 Conceptual Equipment Layouts

To develop conceptual layouts for the production equipment, associated systems and riser handling systems, the approximate deck dimensions of a large semi-submersible drilling rig were selected to establish whether the primary equipment identified could be satisfactorily located with such an area.

Typically, the deck area of a large, twin-hulled semi-submersible may be in the order of 231 ft. long overall x 197 ft. wide overall = 45,507 ft.^{2} (based on the SEDCO 709).

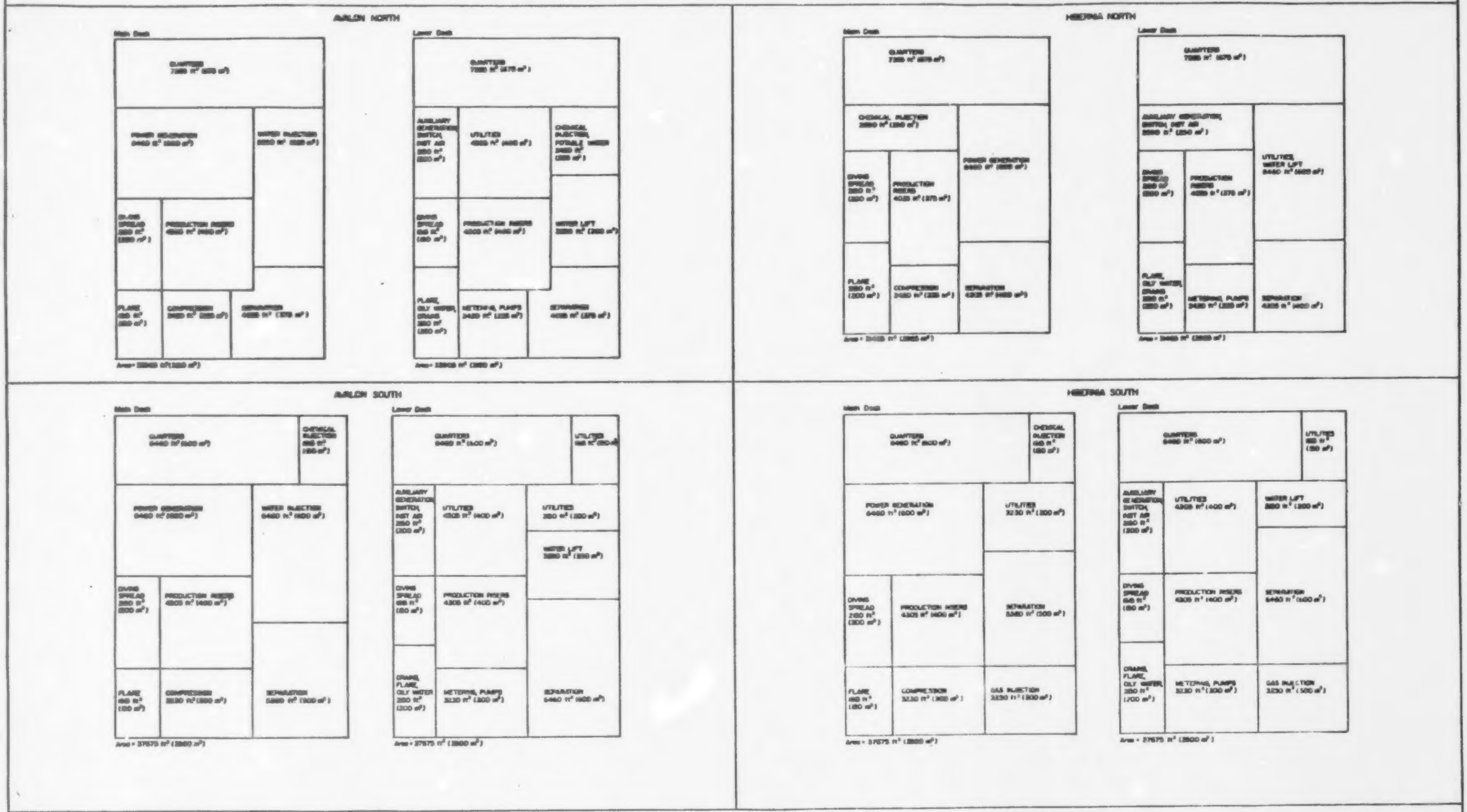
Two decks were utilized for the main equipment and the layouts derived are illustrated in Figure 5-1. They demonstrate that the deck area of conventional large semi-submersibles is adequate to accept the equipment as defined for the purposes of this Study.

Depending on riser design, with the possibility that two separate risers may be required, the areas allocated to production risers in the layout must be considered minimum.

Additional equipment would be located above the main deck, e.g., riser handling systems, additional accommodation, storage, cranes, flare mast/booms, etc.

The layouts as developed include consideration for the safety of the platform with due care for zoning, the likely location of fire/blast walls, and the safety of personnel.

FLOATING PRODUCTION FACILITIES - CONCEPTUAL DECK LAYOUT CONFIGURATION


AVALON NORTH
Main Deck
QUARTERS 7265 ft² (675 m²)
POWER GENERATION
WATER INJECTION
DIVING SPREAD
PRODUCTION RISERS
FLARE
COMPRESSION 2420 ft² (225 m²)
SEPARATION 4035 ft² (375 m²)
Lower Deck
QUARTERS 7265 ft² (675 m²)
AUXILIARY GENERATION, SWITCH, INST AIR
UTILITIES
CHEMICAL INJECTION, POTABLE WATER
DIVING SPREAD
PRODUCTION RISERS
WATER LIFT
FLARE, OILY WATER, DRAINS
METERING, PUMPS 2420 ft² (225 m²)
SEPARATION 4035 ft² (375 m²)
HIBERNIA NORTH
Main Deck
QUARTERS 7265 ft² (675 m²)
CHEMICAL INJECTION
POWER GENERATION
DIVING SPREAD
PRODUCTION RISERS 4035 ft² (375 m²)
FLARE
COMPRESSION 2420 ft² (225 m²)
SEPARATION
Lower Deck
QUARTERS 7265 ft² (675 m²)
AUXILIARY GENERATION, SWITCH, INST AIR
UTILITIES, WATER LIFT
DIVING SPREAD
PRODUCTION RISERS 4035 ft² (375 m²)
FLARE, OILY WATER, DRAINS
METERING, PUMPS 2420 ft² (225 m²)
SEPARATION
AVALON SOUTH
Main Deck
QUARTERS 6460 ft² (600 m²)
CHEMICAL INJECTION 860 ft² (80 m²)
POWER GENERATION 6460 ft² (600 m²)
WATER INJECTION 6460 ft² (600 m²)
DIVING SPREAD 2150 ft² (200 m²)
PRODUCTION RISERS 4305 ft² (400 m²)
FLARE 860 ft² (80 m²)
COMPRESSION 3230 ft² (300 m²)
SEPARATION 5380 ft² (500 m²)
Area = 37675 ft² (3500 m²)
Lower Deck
QUARTERS 6460 ft² (600 m²)
UTILITIES 860 ft² (80 m²)
AUXILIARY GENERATION, SWITCH, INST AIR 2150 ft² (200 m²)
UTILITIES 4305 ft² (400 m²)
UTILITIES 2150 ft² (200 m²)
WATER LIFT 2150 ft² (200 m²)
DIVING SPREAD 860 ft² (80 m²)
PRODUCTION RISERS 4305 ft² (400 m²)
CRANES, FLARE, OILY WATER 2150 ft² (200 m²)
METERING, PUMPS 3230 ft² (300 m²)
SEPARATION 6460 ft² (600 m²)
Area = 37675 ft² (3500 m²)
HIBERNIA SOUTH
Main Deck
QUARTERS 6460 ft² (600 m²)
CHEMICAL INJECTION 860 ft² (80 m²)
POWER GENERATION 6460 ft² (600 m²)
UTILITIES 3230 ft² (300 m²)
DIVING SPREAD 2150 ft² (200 m²)
PRODUCTION RISERS 4305 ft² (400 m²)
SEPARATION 5380 ft² (500 m²)
FLARE 860 ft² (80 m²)
COMPRESSION 3230 ft² (300 m²)
GAS INJECTION 3230 ft² (300 m²)
Area = 37675 ft² (3500 m²)
Lower Deck
QUARTERS 6460 ft² (600 m²)
UTILITIES 860 ft² (80 m²)
AUXILIARY GENERATION, SWITCH, INST AIR 2150 ft² (200 m²)
UTILITIES 4305 ft² (400 m²)
WATER LIFT 2150 ft² (200 m²)
DIVING SPREAD 860 ft² (80 m²)
PRODUCTION RISERS 4305 ft² (400 m²)
SEPARATION 6460 ft² (600 m²)
CRANES, FLARE, OILY WATER, 2150 ft² (200 m²)
METERING, PUMPS 3230 ft² (300 m²)
GAS INJECTION 3230 ft² (300 m²)
Area = 37675 ft² (3500 m²)

NOTES - 1. For each zone, the area given indicates the minimum requirement for principal equipment items. Detailed layouts must further allow for structural members, fire/blast walls and auxiliary equipment items.

2. The upper deck (not shown) will accommodate cranes, riser handling systems (part), helideck, telecom/radio tower, etc.

3. Suitable flaring arrangements, i.e. booms/mast, will be required together with lifeboats etc.

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Figure 5-1

5.3 SUPPORT STRUCTURES

Given the inclusion of semi-submersible floating production platforms in the conceptual development plan, it was necessary to validate their application with some degree of confidence, in terms of ability to accommodate the imposed equipment loads and functions.

It is accepted that of all floating vessels, the semi-submersible offers the most stable work platform for production purposes. The motions of a semi-submersible have little effect on the relatively simple equipment proposed for production purposes.

Development of conceptual layouts (refer to Section 5.2.5) demonstrates that adequate deck may be made available on a large semi-submersible.

Riser handling, "per se", is also not expected to present difficulties, given the development of feasible riser arrangements and acceptable limiting operational sea states (in economic terms as a result of downtime).

Of critical importance however is the payload capability of semi-submersibles of conventional configuration.

Semi-submersible exploration rigs are normally assessed in terms of the variable deck load capability which is defined as the margin of vessel deadweight over and above the fixed equipment loads at the operating draught; this margin being available for additional equipment, consumables, tankage, etc. Typically, for large semi-submersibles the variable deck load is in the order of several thousand tons. New construction, severe environment exploration rigs have variable deck loads extending up to 4,000 tons (e.g., the Zapata SS-4000 due for delivery in 1983), while British Shipbuilders' heavy duty drilling semi-submersible design, BS8000 DP, has a deck payload of 8,000 tons. New designs have displacements between 36,000 tons to 40,000 tons at the operating draught.

A number of rigs designers, builders and/or owners have proposed the use of semi-submersibls for use as FPF's. Table 5-2 indicates the typical utilization of conventional semi-submersible designs for production use. Further, it is known that CFEM have extended their PENTA 7000 design to accommodate a deck payload of 10,000 tonne, and that SEDCO have proposed the use of a Series 700 rigs for production duties as follows:

Oil Production	:	160,000 BOPD
Water Injection	:	180,000 BWPD
Gas Disposal/Injection	:	50 MMSCFD
Storage	:	71,000 Bbl
Workover Capability		Yes

From Table 5-2 the percentage breakdown of displacement is as follows:

	Twin Hulled	Pentagone
Lightship	40%	52%
Deck Payload	25%	25%
Bulk Liquids	35%	23%
Displacement	100%	100%

TABLE 5-2 TYPICAL SEMI-SUBMERSIBLE FPF PROPOSALS

HIBERNIA GAS PRODUCTION STUDY

Rig Type	Twin-Hulled	Pentagone
Function		
Oil Production, BOPD	80,000	80,000
Water Injection, BWPD	120,000	120,000
Gas Disposal/Injection, MMSCFD	150	90
Storage, Bbl	40,000	40,000
Workover Capability	Yes	Yes
Weight Breakdown (Long Tons)		
Hull and Outfittings	9,250	11,740
General and Marine Equipment	1,525	2,375
LIGHTSHIP	10,775	14,115
Cranes & Accommodation	415	605
Workover Rig and Fixed Prod. Loads and Variable Deck Load	6,130	6,125
DECK PAYLOAD	6,545	6,730
Variable Tankage	5,805	6,015
Ballast	3,575	200
BULK LIQUIDS	9,380	6,215
OPERATING DISPLACEMENT (tons)	26,700	27,060

Thus, while a lightship and liquid tankage appears to vary as a result of drastically different designs, the deck payload available for production and associated equipment, excluding marine equipment is consistent at 25% displacement.

Assuming that this factor may be applied to the required topside payload for each Hibernia production centre, and including the allowance for riser handling, diving and riser tension, the required semi-submersible FPF displacements are as follows:

	Avalon Zone		Hibernia Zone	
Weight Item (tons)	North	South	North	South
Topside Weight (Operating)	7,450	8,450	7,330	9,590
Riser Handling, etc.	540	540	540	540
Deck Payload	7,990	8,990	7,870	10,130
Operating Displacement	31,960	35,960	31,480	40,520

The above simple analysis indicates that the purpose-built semi-submersibles required for the Hibernia development plan considered here may be of the same order of magnitude size as the largest exploration rigs currently under construction.

It is assumed that conversions of existing rigs are not feasible even if preferred (especially in light of the Buchan conversion experience where a new-build would have achieved a similar cost and programme with fewer problems, although the circumstances which led to the escalation of the Buchan FPF cost may not inevitably arise).

It is recognized that the above analysis can provide an indication only of required FPF size and that detailed investigation and optimization should be carried out to establish FPF requirements, which must also include consideration of motion response. The analysis is considered sufficiently meaningful, however, to demonstrate the acceptability of the development concept adopted for Study purposes.

Despite the naval architectural advantages of the pentagone type of rig (i.e., excellent stability and small relative differences in motion response with heading) the twin-hulled configuration has been adopted here due to the more convenient deck arrangement which may be obtained. Both designs should be considered in basic engineering, however.

The semi-submersible FPF's will need to operate for many years in an exposed environment and as such their design, construction and operational procedures must conform to the highest possible standards of safety. Neither the pentagone or the twin-hulled type can be said to be a preferred design from this point of view (in the light of the disastrous loss of both the "Alexander L. Kielland" in March, 1980 and the "Ocean Ranger" in February, 1982). The long term safety record of semi-submersible rigs, however, is excellent and this type of FPF should continue to be considered for floating production developments.

The design of the purpose-built rigs should take into account their application to a single location permitting extensive optimization of the design against the specific Hibernia environmental characteristics. It should be borne in mind, however, that the life of the Hibernia Field, particularly if extended by use as a gathering centre for other fields, may require an operating life of the FPP and its topside equipment in excess of, say, 30 years. It is considered that with suitable structural analyses, especially as regards fatigue, and given a suitable programme of planned maintenance by replacement for the topside facilities, such a life may be achieved without requiring expensive remedial work or replacement late in the Field life, as long as the economics justify such action.

Of critical importance to the safety of the development concept will be the survival criteria used in the design, the reserve buoyancy and damage stability of the vessel and the emergency procedures proposed and implemented for operation. The satisfactory demonstration of consideration of the above factors, and the means for ensuring that the design conforms to the intent, will also be crucial in the approval of a development plan based on FPF's, similar to that adopted for Study purposes.

5.4 SUBSEA SYSTEMS AND RISERS

5.4.1 System Overview

The extent to which subsea cluster manifold centres, satellite wells and riser manifold bases have been included in the field development concept adopted for Study purposes would make the Hibernia Field the first major offshore field world-wide to be wholly developed by subsea production techniques on such a scale.

The conceptual development plan calls for:

- A minimum of six Cluster Manifold Centres (CMC's) each with a 12 well slot capability
- Four Riser Manifold Bases and associated risers, one beneath each FPF
- Up to 16 (optional) satellite wells
- Riser bases for oil storage systems and shuttle tanker mooring/loading terminals as required (one of each minimum)

The magnitude of such a subsea production development should not be underestimated in terms of systems engineering and development, equipment delivery lead times, cost and offshore installation programme.

In addition, a significant number of in-field flowlines and transfer lines will be required (refer to Section 5.5).

In summary, production, and possibly injection, wells would be drilled through the template section of the CMC, each completed well being tied-back to a common manifold system within the CMC. Additional satellite wells may be tied-in to the CMC and thus to the common manifold system. Bundled flow/control lines would connect the CMC's to the Riser Manifold Base of the FPF. Commingling of flows from/to, say, two CMC's may be provided in each Riser Manifold Base to which satellite wells may be directly tied-back if desired. The Riser Manifold Base would also provide the bottom connection for the Riser which would transmit flow from/to the production deck of the FPF. The Riser Manifold Base would also house manifold systems and pull-ins for in-field transfer lines and export lines.

To the greatest extent possible production/injection wells would be pre-drilled prior to the availability of the production facilities thereby minimizing the development schedule. Post start-up, concurrent drilling/workover/production operations are envisaged.

Each principal subsea component of the system is discussed below.

5.4.2 Cluster Manifold Centres (CMC's)

The following functions must be served by the CMC:

* drilling template
* location of completion and wellhead equipment and tie-back to common header system
* manifolding/commingling of produced fluids
* manifolding/flow splitting of injection water/gas
* through flowline (FTL) tool distribution
* production testing
* system control (hydraulic and multiplex, chokes/valves/ instrumentation
* satellite well pull-ins and tie-back (if required)
* bundled flowline pull-in and connection
* direct workover access

The most common conceptual approach to CMC's is the wholly integrated unit which combines all the above functions into one base structure. A modular approach may be adopted to the design permitting a variable number of wells or satellite pull-ins to be accommodated.

An alternative approach is to separate the template section from the manifold with the advantage that a simple template base may be installed early before the complete manifold system becomes available.

A third alternative is to dispense with the template section each well being separately drilled and completed at, say, 50 ft. centres which is within the mooring system adjustment of the drilling rig. Each well would then be tied-back by means of a flowline bundle to a manifold centre where flows would be commingled for transmission to the Riser Manifold Base. Such a system may offer advantages as regards iceberg damage protection (refer to Section 5.7.2).

A detailed study of the above alternatives is required to determine their relative merits. However, for no other reason than that it represents the "conventional" conceptual approach, the integrated CMC has been adopted for Study purposes.

The only comparable CMC concept is the Underwater Manifold Centre (UMC) developed by Shell UK Expro and due to be installed in the Cormorant Field, North Sea in the summer of 1982. The Shell UMC includes a remote maintenance system which may not be specified for the Hibernia application but can accommodate up to nine subsea wells either drilled through the UMC or as satellites tied-back to the UMC. The entire unit weighs 2,200 tons and measures 172 ft. x 139 ft. x 50 ft. with a production capability of 50,000 BOPD with a water injection capability of 56,000 BWPD, and includes TFL facilities.

The integrated CMC's required for Hibernia may be of comparable size to the Shell UMC.

The wellhead trees may be either wet or dry types depending on the function, accessibility requirements specified and operator preference. Wet trees provide the least complex alternative for the relatively shallow water depths at Hibernia.

As an integrated part of the design and supply of the CMC's, consideration will need to be given to wellhead completion equipment, trees, running tools, completion and workover risers which will be compatible with the CMC systems and the overall well design.

For installation purposes, buoyancy control may be required together with a levelling system and piling arrangement.

Provision must also be made for access and maintenance of all equipment and systems during operation.

5.4.3 Riser Manifold Bases

Each FPF will require a Riser Manifold Base providing the following main functions:

* Receiving produced fluids from the CMC(s) (and satellite wells if necessary);
* Manifolding/commingling/flow splitting produced fluids as required for riser transmission purposes;
* Injection water distribution to CMC's (and satellite wells if necessary);
* Injection gas distribution to satellite wells (and CMC's if necessary);
* Through flowline (TFL) tool distribution;

- * System control (internal to riser base and signal routing to CMC/Satellite wells - hydraulic and multiplex control, valves/instrumentation);
- * Flowline bundle pull-ins and connections (CMC and satellite wells);
- * Transfer line pull-ins and connections (from/to other FPF Riser Manifold Bases);
- * Export oil/gas manifolding;
- * Export line pull-ins and connections;
- * Mandrel connection to the riser with multiple stab-in connections for internal riser lines.

The design of the Riser Manifold Base is envisaged to be modular to accommodate the range of different services required at each production centre.

In terms of connections either with CMC's, other Riser Bases or export lines, Table 5-3 lists those which may be required given the development concept adopted for Study purposes.

Reference should be made to Section 5.5, Figure 5-2 "Conceptual Flowline/ Transfer Line Arrangement" in considering the above table.

Similar to the CMC installation and operational requirements, buoyancy control, levelling, piling, access and maintenance must all be considered.

The Riser Manifold Base will be an integrated design with the FPF riser, interfaced to other CMC's by means of bundled flowlines.

TABLE 5-3 POSSIBLE RISER BASE CONNECTION REQUIREMENTS

HIBERNIA FIELD DEVELOPMENT

	Possible Connection Required			
	Avalon Zone		Hibernia Zone	
Riser Base Connection	North	South	North	South
CMC Flowline Bundles	2	4	2	4
Satellite Well Flowline Bundles(1)	2,say	2,say	2,say	2,say
Oil Export(2)	1	2,poss.	1	2,poss.
Gas Export	-	-	-	1
M.P. Gas Transfer(3)	1	2	1	2
Injection Gas Transfer(4)	-	1,poss.	-	1
Injection Water Transfer	2	2	1	1
TOTAL POSSIBLE CONNECTIONS	8	13	7	13

Notes:
1. Optional; satellite wells may tie-in to either CMC or Riser Base.
2. For minimization of subsea lines, oil export flows from the northern may be commingled with respective flow from the southern platforms.
3. Medium pressure gas from Avalon North assumed commingled with Avalon South gas.
4. Gas injection wells may all possibly be serviced directly from Hibernia South as satellite wells.

It is desirable that in-field lines be piggable, particularly the oil lines, but it is necessary that the main gas pipeline be capable of being pigged/sphered.

For the smaller diameter in-field lines pigging from the FPF platform deck using foam/poly pigs may be feasible with possible use of bi-directional pigs where appropriate. However, it is considered unlikely that pigs/spheres suitable for use in the main gas pipeline will be able to be run from the FPF deck due to bend radii at the larger diameters and the possible use of multiple lines in the riser. Pig/sphere launching will therefore need to be undertaken subsea, a cartridge loading unit/system being incorporated into the Riser Manifold Base. No such major unit exists at this time and would be a new design system specifically for Hibernia. Similar arrangements may need to be made for key in-field lines, should detailed investigation eliminate the possibility of launching and receiving pigs at the FPF deck.

5.4.4 Riser Systems

A major riser system will be required at each production centre connecting the Riser Manifold Base with the production deck of the FPF.

The risers at each location will have different configurations depending on the range and magnitude of functions to be served. A summary of these functions, given the development plan adopted for Study purposes, is given overleaf.

Riser Function/Flow Direction	Production Centre Avalon Zone North	 Avalon Zone South	 Hibernia Zone North	 Hibernia Zone South
Production/In	*	*	*	*
Production Test/In	*	*	*	*
TFL/Bi-directional	*	*	*	*
Injection Water/Out	*	*	-	-
Injection Gas/Out	-	-	-	*
Medium Pressure Gas/In	-	-	-	*
Medium Pressure Gas/Out	*	*	*	-
Control Conduit	*	*	*	*
Hydraulic Supply	*	*	*	*

The number of lines included in each riser and their specification will depend on the throughputs and operating pressures required and this will need to be the subject of detailed study. Of critical importance will be the high pressure systems which comprise

Gas Injection : circa 6,000 to 7,000 psig
Water Injection : circa 6,000 psig
Gas Export : circa 2,700 psig

It may prove not possible, or more feasible, to incorporate all the above functions into a single riser in which case multiple risers may be considered with a possible functional split in terms of production/injection or liquids/gas as convenient.

Two alternatives exist for riser design:

i) Integral - where all lines are rigidly combined into a single unit the riser being subdivided into a reasonable number of joint lengths from a handling point of view; or

ii) Non-Integral - where individual lines are independently removable and supported by a rigid riser core, which may comprise one of the larger riser lines.

Non-integral risers are more applicable where individual well flowlines may be brought to the surface and/or where production rates and service requirements are relatively low. For the Hibernia application, however, moderate to high flowrates and considerable service functions and throughputs are required. Also, the handling of an integral riser will be faster than a non-integral type thereby reducing weather downtime, although a non-integral type may have an increased survival sea state with individual lines removed but the central core connected thereby reducing connection time. An integral type riser has been assumed for Study purposes but final selection of type will depend on detailed analysis.

From a structural viewpoint the design of the riser should not pose major technical problems in the moderate water depths at Hibernia, unless the overall diameter and weight of an individual riser becomes excessive. The riser may possibly be built around a central core, or may be enclosed within a sheathing. Buoyancy material may be utilized to reduce tensioner loads.

Individual riser joint lengths may vary between, say, 50 ft. to 100 ft. depending on overall riser length (say, 320 ft.) and handling arrangements, particularly set-back when disconnected. Connections between individual riser joints may be made utilizing a single central hydraulic collet plus clamp connections for other lines. Connection to the Riser Manifold Base may be by collet connector for large lines plus stab-ins for small lines. Pressure integrity of the connections will be critical for the high pressure systems and will be an essential part of the design.

Excursions of the FPF relative to the Riser Manifold Base may be accommodated at the base of the riser by means of a flex-joint in all large lines above the bottom connection with stress type joints for smaller lines. A conventional riser tensioning system is envisaged at the top of the riser, centralized for use with the integral riser design, with connections to the production deck manifold by means of flexible jumper hoses.

The design of the bottom assembly of the riser must incorporate an emergency disconnect capability and riser design must include attention to behaviour and risk of damage to the riser and the FPF when the riser is freely suspended beneath the FPF in severe weather. Consideration may be given to alternative approaches to emergency disconnect such as a mid-water separation with adequate buoyancy in the lower section to maintain integrity with the bottom connection in place.

5.4.5 Integrated Design of Subsea Systems

An essential part of the design and engineering of the production facilities for Hibernia will be the integrated development of the subsea systems. In many cases, subsea production systems are often designed simply by combining existing equipment, up-rated and modified as required, into an overall package, components often deriving from a wide range of vendors. Compatibility between the different systems and the minutiae of the design often causes the most significant operational difficulties with subsea systems. All components therefore:

- Cluster Manifold Centres
- Satellite Wells
- Flowline/Control Line Bundles

- Riser Manifold Bases
- Riser Systems

should be part of an integrated development with considerable systems design preceding detailed engineering.

In terms of the success of the Hibernia development, given the concept adopted for Study purposes, the design, engineering, and supply of the Subsea Systems will be one of the critical activities requiring considerable new innovative design and development activity. The concept is considered to be a reasonable extension of current technology, however.

5.5 IN-FIELD FLOWLINES AND TRANSFER LINES

Given the function of the individual production centres defined in Section 3.4, the corresponding conceptual flowline/transfer line arrangement is shown in Figure 5-2 and includes:

* CMC/Riser Base Bundled Flow/Control Lines
* CMC or Riser Base to Satellite Wells Bundled Flow/Control Lines
* Injection Water Transfer Lines
* Medium Pressure Gas Transfer Lines
* Injection Gas Transfer Lines
* Oil Export Lines

It is assumed that inter-platform lines would be laid in pipeline "corridors" rather than being located haphazardly across the seabed to minimize the risk of accidental rupture by barge anchors, etc., and the lines would be trenched, and backfilled if possible, to provide additional protection. Trenching without burial or effective natural backfill confers no valid protection from trawl boards. Even relatively deep burial offers little protection from large anchors. To reduce the risk from marine activity, it is desirable that the sea area within the perimeter defined by the four FPF's should be a restricted area other than for right of passage. Purpose designed, permanent supply vessel bow moorings may also be considered.

The actual routing of the flowline bundles will depend on the location of the CMC's and the satellite wellheads relative to the Riser Manifold Bases and the arrangement of the transfer lines will be influenced by approach arrangements for pull-in at either end.

For overall security of supply, two flowline bundles have been included between the CMC's and their respective Riser Bases; one operating plus one spare. Considerations in detailed design may result in the sparing of key transfer lines.

A typical group flowline between the Riser Manifold Base and a CMC, or from a satellite well, would contain the following lines bundled inside a large diameter, concrete coated, carrier line:

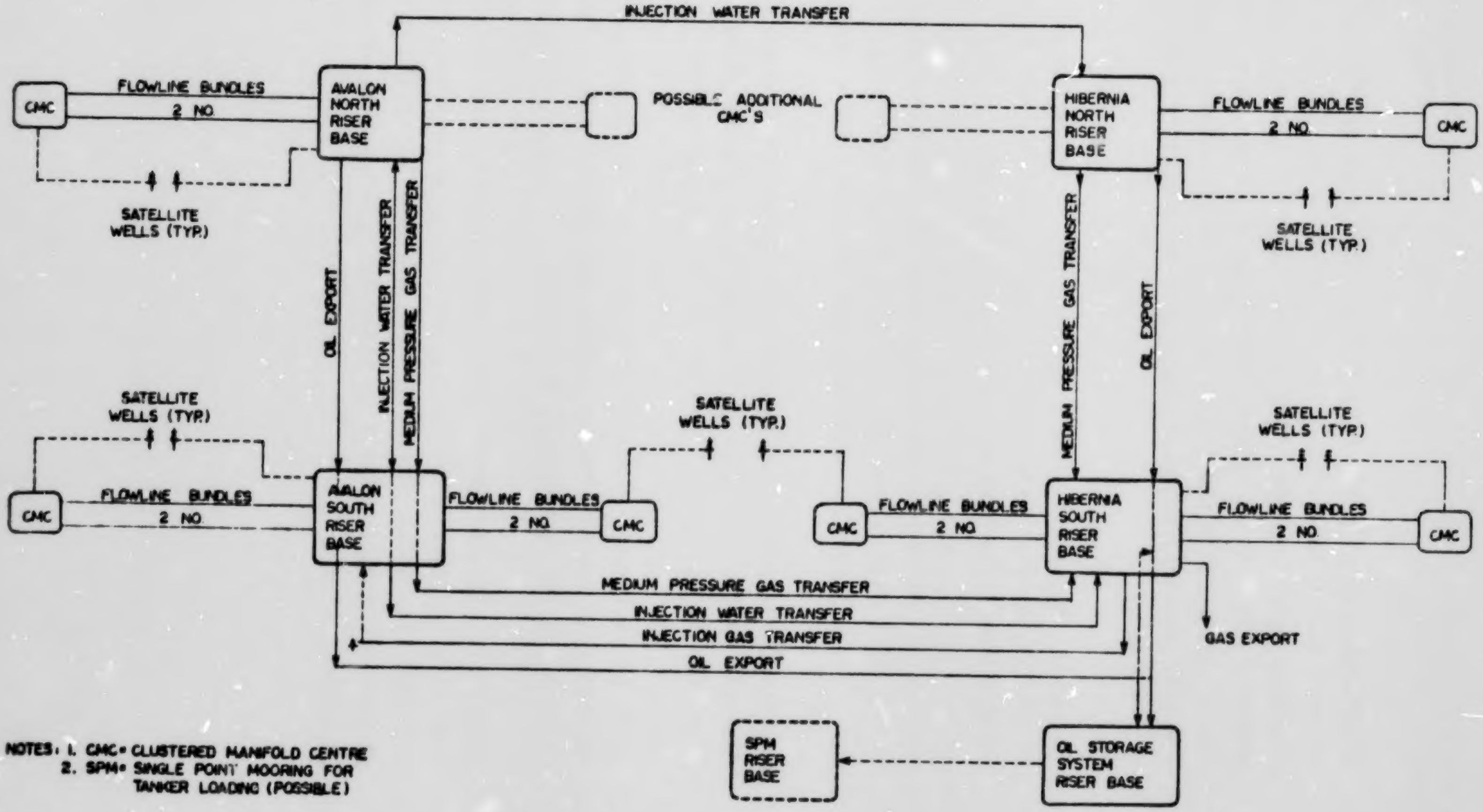
Bundled Flowline/Control Lines

CMC to Riser Manifold Base	Satellite Well
2 No. Production Lines	2 No. Production Lines
1 No. Production Test Line	1 No. Control Conduit
1 No. TFL Line	1 No. Hydraulic Supply Line
2 No. Water Injection Line	
1 No. Control Cable Conduit	
1 No. Hydraulic Supply Line	

Gas injection lines may also be incorporated into the CMC bundles but it is considered more likely that these may be satellites serviced directly from the Hibernia South Riser Base. Satellite wells may also be used for water injection serviced from the Riser Base or CMC.

Water injection facilities are provided only on Avalon North and South. It is considered necessary to be able to convert "watered-out" producing wells into water injection wells if appropriate. To enable this to be done in the Hibernia zone an injection/water transfer line has been included between Avalon North and Hibernia North, and between Avalon South and Hibernia South.

HIBERNIA FIELD - CONCEPTUAL FLOWLINE/TRANSFER LINE ARRANGEMENT


INJECTION WATER TRANSFER
CMC
FLOWLINE BUNDLES
2 NO.
AVALON NORTH RISER BASE
POSSIBLE ADDITIONAL CMC'S
HIBERNIA NORTH RISER BASE
FLOWLINE BUNDLES
2 NO.
CMC
SATELLITE WELLS (TYP.)
OIL EXPORT
INJECTION WATER TRANSFER
MEDIUM PRESSURE GAS TRANSFER
MEDIUM PRESSURE GAS TRANSFER
OIL EXPORT
SATELLITE WELLS (TYP.)
SATELLITE WELLS (TYP.)
SATELLITE WELLS (TYP.)
SATELLITE WELLS (TYP.)
CMC
FLOWLINE BUNDLES
2 NO.
AVALON SOUTH RISER BASE
FLOWLINE BUNDLES
2 NO.
CMC
CMC
FLOWLINE BUNDLES
2 NO.
HIBERNIA SOUTH RISER BASE
FLOWLINE BUNDLES
2 NO.
CMC
MEDIUM PRESSURE GAS TRANSFER
INJECTION WATER TRANSFER
INJECTION GAS TRANSFER
OIL EXPORT
GAS EXPORT
SPM RISER BASE
OIL STORAGE SYSTEM RISER BASE

NOTES: 1. CMC = CLUSTERED MANIFOLD CENTRE
2. SPM = SINGLE POINT MOORING FOR TANKER LOADING (POSSIBLE)

Figure 5-2

Since the water injection facilities have been shared equally between Avalon North and South, a further water transfer line is included between these two platforms to allow for any imbalance in demand. There is in effect, therefore, a subsea injection water header system enabling injection wells to be located either at the CMC's or remotely as satellites serviced either from the Riser Bases or the CMC's.

To reduce the overall number of transfer lines, and hence the risk of damage, several flow functions may be combined subsea at the Riser Bases. Combinations may be as follows:

i) Oil export at Avalon South and Hibernia South
ii) Medium pressure gas transfer at Avalon South
iii) Injection water transfer at Avalon north and South

Oil from Avalon may also be commingled with Hibernia oil at the Hibernia South Riser Base or alternatively a direct line or a subsea "Tee" may be utilized.

With the inclusion of remote shuttle tanker mooring/loading terminals, transfer lines will also be required between the storage unit(s) and the terminal(s).

Indicative sizes of the in-field transfer lines are given in Table 5-4. The length of CMC Bundles and satellite bundles may typically be 5,000 ft. radius each from the Riser Base while the total length of in-field transfer lines as shown in Figure 5-2 is in the order of 35 miles.

TABLE 5-4 INDICATIVE SIZING OF IN-FIELD TRANSFER LINES

HIBERNIA FIELD DEVELOPMENT

Transfer Line Category		Indicative Size
1. CMC-Riser Base Bundles	say,	24" Carrier Line
2. Satellite Well Bundles	say,	10" Carrier Line
3. Injection Water Transfer Lines		
A. Avalon North - Avalon South	say,	2.4 miles, 18"
B. Avalon North - Hibernia North	say,	3 miles, 10"
C. Avalon South - Hibernia South	say,	3.1 miles, 14"
4. Injection Gas Transfer		
Hibernia South - Avalon South	say,	3.1 miles, 8"
5. Medium Pressure Gas Transfer		
A. Avalon North - Avalon South	say,	2.4 miles, 8"
B. Avalon South - Hibernia South	say,	3.1 miles, 12"
C. Hibernia North - Hibernia South	say,	3.2 miles, 10"
6. Oil Export		
A. Avalon North - Avalon South	say,	2.4 miles, 10"
B. Avalon South - Storage	say,	5 miles, 16"
C. Hibernia North - Hibernia South	say,	3.2 miles, 10"
D. Hibernia South - Storage	say,	1.9 miles, 14"
E. Storage - Moor/Load Terminal	say,	1.9 miles, 24"

5.6 CRUDE OIL STORAGE SYSTEM

For offshore field developments without a liquids pipeline to shore, the offshore mooring and loading of shuttle tankers is the only alternative means of export for crude oil. Such an export system will suffer from weather downtime as a result of sea states occasionally exceeding the operational limits of the system.

The inclusion of offshore storage in the system acts as a "buffer" permitting production to continue during periods when shuttle tanker loading is not possible. The inclusion and capacity of such storage depends on the life cycle economics of the system. For relatively small, low production rate oil fields, even in relatively severe environments, storage may not be economic; the field simply loading tankers at the production rate when possible, the wells being shut-in during weather downtime. It is necessary to demonstrate that such a discrete production approach will not cause significant loss of recovery from the reservoir. With low flowrate fields, the deferred production during weather downtime and tanker changeover may be acceptably small.

For larger fields with higher flowrates, say, 80,000 BOPD and above, the inclusion of storage will, in general, be beneficial, particularly in severe environments.

Conventional semi-submersible FPP designs with operating displacements up to, say, 40,000 tons, cannot accommodate significant levels of storage, say, 40,000 to 70,000 bbl, depending on required payload, structural steelweight, etc. Such a volume may be adequate for small fields and is useful as a production "surge" buffer or during shuttle tanker changeover at the mooring loading terminal.

For Hibernia, a larger volume of storage will be required due to the high production rate and the severe environment. Several alternative storage concepts may be considered:

- integral, where storage is integrated with the production structure, such a structure possibly comprising:
  - a fixed platform of the steel or concrete gravity type;
  - a process/storage ship-shape vessel;
  - a large steel/concrete semi-submersible or buoy type
- remote, where storage is provided in a facility separate from the drilling/production centre, such a facility possibly comprising:
  - floating storage in a ship-shape or large semi-submersible vessel;
  - seabed storage in a tank located on the seabed.

Provision may be made in all the above to accommodate in the order of 1 MM bbls storage; possibly greater amounts with fixed gravity platforms and lesser amounts in novel semi-submersible/buoy types. A 225,000 ton dwt. tanker, if fully utilized, would accommodate 1.5 MM bbls, but, unless alternative provision is made for treating ballast/oil displacement water, utilization may be only 60% (i.e., 1 MM bbls) to allow for segregated ballast.

The determination of required storage volume should be undertaken through the use of a computer model which simulates production/storage/mooring/loading operations offshore together with shuttle tanker voyage characteristics. Such models, which are available, are stochastic and predict the probability of achieving specific levels of overall production efficiency with various combinations of principal facilities, capacities and production/loading rates. The data derived is used in the economic models of the field to select the required level of storage, together with technical evaluation and selection of preferred facilities type.

As a "rule of thumb", 7 to 10 days storage is required in severe environments to reduce downtime due to the offshore mooring/loading operations to below 10%. Thus for Hibernia, a storage volume of at least 2 MM bbls is required, 3 MM bbls being more acceptable due to the particular characteristics of the environment. This is a preliminary estimate only and must be confirmed by computer simulation.

Given the development concept adopted for Study purposes, fixed structures and seabed storage are excluded from consideration due to the risk of damage from icebergs. The concept calls for some form of floating storage. It is known that Mobil is considering a novel semi-submersible storage tank capable of storing 1.15 MM bbls of oil as one option for providing storage but at this time such vessels are not proven. Considerable structural design and motion response analysis and model tests will be required to valididate the concept. Large, semi-submersible/buoy types of vessel may not be applicable due to operating draught limitations in the Hibernia water depths.

For Study purposes, therefore, the conventional approach of using a converted tanker for storage has been adopted, its feasibility for the Hibernia application and relative merits compared to alternative storage concepts requiring detailed investigation and model testing. Mooring system selection will also required detailed study but may comprise a turret mooring, rigid yoke or submerged SALM. Turrets and yokes have the advantage of product swivels being located above the water line. A critical aspect of such study will be the minimization of damage risk to hoses, etc., in severe sea states, the general integrity of the system for long term use, and the minimization of damage in the event of iceberg collision. A seabed or mid-water emergency riser disconnect capability may be specified or alternatively the mooring system may be laid down on the seabed.

Riser design for the storage system must include import and export lines but is not a complex problem.

For use in summer or calm weather, a stern-to-stern mooring capability for shuttle tankers may be considered providing fast moor-up and loading with the minimum of equipment. A side-by-side system may be applied in ice and moderately severe weather conditions. However, for more severe sea states, a remote mooring/loading terminal is required. This should be of the severe environment type permitting self-mooring by shuttle tankers to eliminate the need for service boats. Typically, an Articulated Loading Tower (ALT) may be considered. In many cases offshore, improvements in operating efficiency have been achieved through the use of two remote terminals.

Should considerable quantities of NGL be produced offshore, a separate NGL export line to the storage vessel may be considered with possible storage of NGL in deck tanks, depending on volumes. A separate NGL remote mooring/loading system would then be required using LPG shuttle carriers. Such systems will add considerably to the operational complexity of the Hibernia development. Also, given the "dense phase" gas pipeline operating philcsophy adopted here, quantities of residual NGL should be small and may be used as fuel gas. NGL export by shuttle carrier has therefore not been considered.

To provide adequate storage tanker "weathervaning" about its mooring and to allow maneouvring space for shuttle tankers together with a safety margin, the storage system should be remote from the production centres, say 2 miles, and not be located within the perimeter of the Field as defined by the production centres. In turn, the remote mooring/loading terminals must be equally remote from both the production centres and the storage system.

For the purposes of cost assessment, two yoke-moored 225,000 ton dwt. storage vessels (providing a total of 2 MM bbls oil storage) together with two remote mooring/loading terminals have been included.

The shuttle tankers, possibly 130,000 ton dwt. with segregated ballast would require some bow and piping modifications for use in the system. Such vessels would be chartered in order to match the size and number of vessels to the varying production rate over the life of the Field. Given a 2,000 nautical mile, round voyage distance, which would permit oil discharge at, say, Portland, Maine, U.S.A if required, approximately 8 to 10 such shuttle tankers may be required to meet the export demand at peak year production rates.

5.7 CONSTRUCTION AND INSTALLATION

5.7.1 Construction

Given the utilization of floating production facilities, it is envisaged that, following construction of the hulls of the semi-submersible support structures, the installation of production equipment and other topside facilities would be integrated with the construction of the FPF deck. Such an integral deck approach offers considerable weight savings in structural steelwork compared to modularization. Structural steelwork is restricted to localized equipment support and skid beams/areas.

Construction of the semi-submersible hull, together with hull outfit items, may thus be accomplished at a suitable shipyard or construction dock, the hulls being floated out for topside completion at the dockside, not necessarily at the same site.

All topside facilities would be hooked-up and pre-commissioned at the dockside, thereby reducing offshore commissionning requirements. The objective of minimum offshore construction should be adopted.

The crude oil storage unit(s) would similarly be constructed or converted depending on system choice at a suitable shipyard/ construction site.

The in-field flowline bundles would be fabricated at a suitable site in Newfoundland offering minimum off-bottom towage distance to the Hibernia location. The in-field transfer lines, if either off-bottom towed to the location or laid by reel barge, may be fabricated at the same site, which may also provide the pipe wrapping/coating services for the main gas pipeline.

5.7.2 Subsea Equipment Iceberg Scour Protection

The overall installation schedule will be influenced not only by the time to complete the design, engineering construction and pre-commissioning of the production facilities, but also by the need to pre-drill an adequate number of production and water/gas injection wells to support initial production from the Field.

The installation of CMC's (or at least the drilling template modules of the CMC's) and subsequently the Riser Manifold Bases depends in turn on whether the decision is taken to protect wellheads and subsea equipment from iceberg scour and, if affirmative, by what method. This aspect, and the installation of the major components of the development, is dealt with below.

It is generally accepted that simply given the risk of iceberg scour at the Hibernia location, some degree of protection must be provided for subsea equipment. Of critical importance will be protection of wellhead equipment and the means of ensuring that individual wells can be accessed following any iceberg scour incident.

The risk of an iceberg scouring a specific CMC or Riser Manifold Base location may be low due to the relatively small area of seabed at risk together with the possibility of diverting icebergs of reasonable size by means of towing. The acquisition of additional scouring data and a detailed risk analysis may indicate that the risk to certain items of subsea equipment, e.g., Riser Manifold Bases or individual satellite wellheads, may be within acceptable limits in terms of risk/cost relationships. Detailed attention will need to be given to the risk of pollution as well as damage.

It is not within the scope of this Study to carry out such a risk analysis and it must therefore be assumed that iceberg scour protection is required until additional studies demonstrate otherwise.

A high degree of protection may be afforded by installing subsea equipment in seabed excavations or "glory holes". Assuming an excavated "glory hole" 50 ft. deep with a bottom area of 200 ft. x 150 ft. (which should be adequate clearance to locate a 12-slot CMC or major FPF Riser Manifold Base) and an excavation wall gradient of 1:2, the volume of spoil required to be removed may be in the order of 145,000 cubic yards. Volumes for oil storage/mooring/loading riser bases may be less, say, 122,000 cubic yards. Such "glory holes" will require the development of new excavation systems capable of operating in the 280 ft. water depths and handling the semi-consolidated Cretaceous-Tertiary bedrock underlying the thin covering of sand and gravel surficial sediments at the Hibernia location. No engineering soils data suitable for assessing such equipment requirements is available to the Study at this time. High pressure jetting and eduction equipment may prove suitable depending on soil characteristics but the possibility that mechanical excavation methods may be required should be borne in mind. The occurrence of boulders or extensive areas of consolidated bedrock may require the use of blasting and/or clamshell grab excavation. Only one design for a clamshell grab dredge suitable for the Hibernia water depths has been extensively engineered and tested, this being the suspension line system developed by Groupement Europeen de Recherches Technoliques sur les Hydrocarbures, a joint venture of CFP, IFP and SNEA(P)[1]. Assuming that such a system

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1. DeVries, J., "An Offshore Seabottom Excavation System" Proc. of the Sym. on Production and Transportation Systems for the Hibernia Discovery", St. John's, Newfoundland, Feb. 16-18, 1981.

could be engineered to excavate an average 1,000 cubic yards per day using a small semi-submersible vessel at 40% downtime during an eight-month weather window, then approximately one 145,000 cubic yard "glory hole" would be completed per season per excavation rig. On this basis seabed excavations will be time consuming and expensive. For the purposes of the cost assessment, such a system has been assumed, four such excavation rigs being required to achieve sufficient lead time for installing the CMC's and pre-drilling the development wells.

The development of underwater cutter suction dredging equipment, such as John Brown Subsea's "Drill Stem Miner", may allow faster excavation rates to be achieved with greater control over the excavation profile especially in achieving a level base for CMC's, etc. For example, the "Drill Stem Miner" is rated at an average excavation rate of approximately 500 cubic yards per hour in heavy clay giving a daily rate in the order of 10,000 cubic yards at an 80% utilization factor. Due to this fast rate such systems should be considered for the Hibernia Field but their application will depend on the characteristics of the semi-consolidated tertiary "bedrock" and the occurrence of boulders/hard rock areas.

Given the available data on soil, iceberg scour risk/frequency and iceberg behaviour during scour, it is not possible in this preliminary investigation to quantify the technical and economic necessity for extensive seabed excavations. Detailed study may indicate that the use of, say, a 50 ft. deep "glory hole" does not provide acceptable protection in that:

i) the scouring iceberg may "drop" or capsize into a "glory hole" the dynamics of the situation creating additional risks to equipment;

ii) the berm raised by the scouring iceberg would be driven into the "glory hole" thus covering/damaging equipment unless considerable clearance is provided, at increased cost.

The extremely high cost and lengthy duration required for "glory hole" excavation demands detailed study of the true level of risk and alternative means of protection including possible combinations of:

- iceberg deviation by towing
- individual caisson completed wells
- minimum height wellhead, CMC, etc., equipment
- deep downhole safety valves
- berm protection or combined berm/excavation protection

It is essential that such detailed study quantify the statistical risk and associated value of the alternative protection systems in order that the optimum method of protection and associated operational procedures may be defined.

To reduce the risk of damage to in-field flowlines and transfer lines, these should be trenched. The required depth of cover to reduce the risk to acceptable levels is not quantified at this time, although depths of 7 ft. to 10 ft. have been suggested in order to reduce the probability of damage to once in 250 years. Mobil, however, suggest that depths in excess of 12 ft. may be required.

In suitable soils, conventional jetting may achieve depths of cover up to, say, 12 ft. The maximum known depth of cover for a pipeline is 22 ft. in sandy clay offshore Nigeria. The sand and gravel layers overlying the Cretaceous-Tertiary "bedrock" at the Hibernia location are variable in thickness and may not provide sufficient depth, or strength, or cover. Jetting may be feasible in the semi-consolidated "bedrock" but engineering soils data is required for an assessment of achievable depth with conventional equipment. In any event, multiple passes will be required. Mechanical cutter trenchers, which are few in number and the prototypes of which have seen little general application, may be required.

5.7.3 Installation

The overall installation sequence will span several years and will commence with the installation of the CMC's (or at least the drilling template modules) to enable pre-drilling to commence. The various riser bases and in-field flowlines/transfer lines would then be installed in accordance with a logical sequence the start and termination dates of which will be influenced by the earliest start of pre-drilling and the scheduled availability of the floating production platforms for tow-out and installation. In general, offshore work will be scheduled within a summer "weather window" of, say, 6 months with possible earlier mobilization as required and work continuing beyond the "weather window" if weather conditions and the contractual requirements for construction vessels are suitable. Typically, the construction "weather window" may extend from May through October.

The CMC's and Riser Manifold Bases will require to be piled into the seabed following submergence. Levelling to acceptable tolerances must also be carried out, the CMC/Riser Base being clamped or grouted into a fixed position once levelled. The storage/mooring/loading riser bases are also likely to require piling although gravity base designs are available.

Depending on the design concept, the CMC's/Riser Bases units may be loaded out and transported to the Hibernia location by barge or towed out utilizing built in buoyancy. Due to the high cost of the components, barge transportation is to be preferred. At the location the units would be offloaded and submerged, either using a derrick barge or by keel-hauling beneath, say, a semi-submersible rig. Full survey position fixing and diving support will be required for both site preparation and installation. Piling would ideally be carried out using underwater hammers.

Installation of in-field flowlines/transfer lines may be a combination of off-bottom tow, reel barge and conventional laying depending on circumstances and the availability of suitable equipment. Trenching would be achieved using either jetting or mechanical equipment, as appropriate, operated from, say, a small semi-submersible laybarge.

Given the installation of the Riser Manifold Bases, the installation requirements of the Floating Production Platforms (FPP's) are minimal. Due to the permanent and extensive nature of the installation, e.g., four FPP's each with, say, 12 mooring lines, piled anchors may be preferred for the FPP mooring system since difficulties may be experienced with conventional anchor systems given the semi-consolidated Tertiary soils anticipated. Installation of these piled anchors may also be carried out using underwater hammers, a temporary alignment base and, say, a semi-submersible rig.

The mooring spread for the FPP's may either be pre-laid or run when the vessel arrives on location. In any event, following installation of the piled anchors and tow-out of an FPP, installation is limited to hook-up of the mooring system and initial deployment of the production riser. The requirement for offshore topsides equipment installation and hook-up should be minimized and, due to the extent of pre-commissioning, final commissioning of the system should be rapidly achieved.

It is considered that the concurrent installation of all four FPP's in a single season is not realistic due to difficulties in scheduling simultaneous construction and equipment supply and also due to likely congestion of construction vessels offshore, particularly with respect to installing and piling all CMC's, Riser Bases and anchor piles prior to arrival of the FPP's. The installation of two FPP's per season is not considered unachievable, given proper project management, and should also permit realistic phasing of onshore construction and equipment supply.

Given the extent of subsea equipment installation and flowline/transfer line pull-ins required, the use of a semi-submersible rig for construction purposes throughout the duration of the offshore work may warrant consideration. This should maximize the length of the "weather window" and the rig may be used for drilling/workover purposes when not required for construction.

5.8 CRITICAL AREAS OF THE FLOATING PRODUCTION FACILITIES

It is emphasized that adoption for Study purposes of the individual components of the development has not arisen as the result of a detailed comparison and evaluation of the technical, operational and economic merits of the wide range of alternatives which may be considered. Rather, a reasonable development concept has been adopted with the objective of assessing the integration of gas transmission systems and for the purposes of developing an indicative cost assessment for the development in order to place gas transmission system costs in perspective. The technical definition of the adopted components included in the previous Sections is provided to establish the basis upon which to consider the integration of gas systems and their associated costs but is not intended to exclude alternative development concepts from consideration or suggest any preference for particular components at this time. This must be the subject of an overall Field Development Planning Study.

5.8.1 Support Structures

With regard to the use of conventional configurations of semi-submersibles the following aspects will be critical to their successful application.

i) Minimization of topside equipment weight and space requirements. Topside payloads in excess of, say, 10,000 tons will require a semi-submersible of a size larger than any currently designed or under construction. This should not be a problem, however, since increases in operating displacement can be readily designed.

ii) Optimization of the hull configuration against the specific environmental characteristics at the Hibernia Field (since such platforms may be dedicated to use at Hibernia and need not include the ability to operate elsewhere due to the long life of the Field).

This will include both structural design and motion response, the latter serving to minimize production shutdown due to weather.

iii) Maximum attention to structural integrity, especially fatigue, over the design life of the platform which may be in excess of 30 years.

iv) Maximum attention to the intact and damaged stability of the vessel both in the moored and mobile condition.

Extensive structural design analysis and model testing will be required to determine the optimum FPP configuration.

5.8.2 Topside Facilities

The topside production equipment will be of conventional design commensurate with the efficient separation of oil and gas and processing to the required export specification. Critical design aspects of the facilities will be:

i) Definition of the average and peak design operating throughputs at each production centre taking into account all aspects of production deferment or losses due to downtime, and variation over the life of the Field.

ii) Definition of the composition of produced fluids and the production characteristics, e.g., flowing pressures and temperatures, including variation over the life of the Field and including details of water production.

iii) Definition of the required water and gas injection rates over the life of the Field and the acceptable composition of injected fluids.

iv) Specification of the required composition and characteristics of export products.

v) Definition of all safety systems, including fire and gas detection, and evacuation methods and procedures.

The above will require detailed knowledge and analysis of the reservoir, including computer simulation/optimization. Further, due to the inclusion of FPP's and the complexity of the development, considerable benefit may be gained through the development of an operational computer simulation model of the Field to predict required stream day offtake production rates, storage volumes, etc.

Due to the requirement to produce both stabilized crude oil for tanker loading and gas for export, a critical design area will be the handling of intermediate fractions (NGL's). The optimization of the process will require considerable process analysis, simulation and optimization to determine the preferred philosophy, operating conditions and quantities of NGL's available. The acceptability of a "dense phase" gas transmission system operating at high inlet pressures and the means of controlling the vapour pressure of the export oil stream below the limiting RVP for storage and tanker export (say, 10 to 14 RVP) will be critical aspects of the design.

5.8.3 Subsea Systems and Risers

It considered that all aspects of the subsea equipment requirements are reasonable extensions of current technology. The magnitude of the requirements means that considerable innovative design and development engineering will be required since suitable systems are not available "off-the-shelf" and must be purpose designed.

Aside from the question of protection from iceberg scour, the lead time required to complete the integrated systems design of the Clustered Manifold Centres, Riser Manifold Bases and Riser systems, will be considerable. Such systems design is critical since installation of the CMC's controls the pre-drilling programme. The possible physical separation between the drilling template function of the CMC and the manifolding function will be a key consideration for advancing the pre-drilling programme through early installation of the template sections. Detailed investigation of the CMC concept and the alternative approaches, e.g., separate, caisson completed wells tied-back individually to a local manifold centre, may indicate advantages of an alternative approach to the CMC.

With the CMC situated remote from the FPP, well control will be a critical design aspect. Further, workover is limited to Through Flowline (TFL) tools a separate workover rig being required for major well and wellhead equipment maintenance. Detailed investigation is required to establish the relative merits of either remote or direct access to the wells from the FPP. Where topside weight and space restrictions apply, the elimination of direct access and workover capability from each FPP simplifies the overall design of the FPP, and eliminates unnecessary duplication of equipment. Given the potentially high number of wells required for reasonable depletion of the Field, such detailed investigation may indicate that dedicated workover rig(s) provide a cost effective solution. Remote CMC's increase the inherent risk of damage due to iceberg scour of flowline bundles, the quantification of such risk and the benefit of potential trenching having been already highlighted as a critical area for further study.

Despite the possible restrictions which may be placed on marine activity, e.g., fishing, shipping, in the area, the investigation of damage to wellheads and CMC's from such activities must be investigated and suitable protection provided if needed.

As with all floating production facilities, riser design is a critical aspect. The adoption of shared facilities function between FPP's and the inclusion of gas export in the system does not add considerably to the extent of riser requirements compared to each FPP being an independent facility. Riser design for FPP's operating in severe environments is critical since the design operating limits control the overall downtime of the facility due to weather. Operational riser behaviour analysis and model testing as an integrated part of the FPP structural design will be important. Such analysis will establish the preferred extent of seabed manifolding to be used, the extent to which multiple lines for particular functions are desirable and may indicate a need for multiple risers. Further, the relative merits of integral risers as compared to risers with individually retrievable lines must be established in terms of riser behaviour, emergency disconnect, limiting operational sea states for disconnection and reconnection, convenience for repair/maintenance and speed of handling. For Study purposes integral risers are assumed due to speed of handling but the final choice will depend on detailed study. Of critical importance as regards riser line and connector specification will be the high pressure gas lines. Suitable connector designs are, however, currently available.

5.8.4 In-Field Flowlines and Transfer Lines

The development concept as adopted calls for extensive in field flowlines and transfer lines, say, 45 miles including CMC bundles.

Critical to the acceptability of this arrangement will be the relative risk of iceberg damage and the potential for deep trenching in the soils at the location. It is anticipated at this time that conventional jetting or mechanical trenching will provide some protection, but the quantification of depth of cover achievable and acceptable will require further site studies.

It is essential that all flowlines and transfer lines be firmly anchored close to the CMC's or Riser Manifold Bases to prevent damage to the subsea equipment in the event that a line is dragged by anchors, etc., close to the equipment.

The tie-in of the various flowlines and transfer lines to the CMC's and Riser Manifold Bases will be an important part of the design. Due to possible pour-point problems, design consideration will also have to be given to the back-flushing of flowlines and the upper sections of the well bore with diesel oil, or the addition of chemicals, prior to periods when the lines are shutdown.

5.8.5 Crude Oil Storage System

Quantification of the storage system requirements, e.g., volume, number of mooring/loading terminals and number and size of shuttle tankers, through computer simulation is essential for the production rates considered and the environmental conditions anticipated.

Full analysis of the life-time structural integrity and mooring requirements of the alternative systems must be carried out due to the severe sea states at Hibernia. The use of floating storage is assumed as part of the floating production systems premise. The development concept as adopted for Study purposes assumes a moored tanker for no other reason than its conventional nature. Detailed investigation and model tests may indicate a preference for alternative vessel designs, such as Mobil's semi-submersible, if it is considered that the long term application of a ship-shape vessel is not feasible or will lead to excessive downtime.

Whatever floating vessel is selected for storage use, its mooring/riser system must be capable of being readily disconnected, and re-connected, in the event of iceberg, or other vessel, collision risks arising.

5.8.6 Construction and Installation

Construction of semi-submersible FPP's of the size and function envisaged is not considered to be a problem.

The integrated installation and pre-commissioning of the topsides equipment within the FPP structure is considered a critical aspect for the successful and cost effective implementation of the project.

The overall magnitude of the offshore installation task will require several years to complete, despite the fact that the FPP installation and commissioning requirements are minimal. Critical to the development plan as adopted, and project cost, is the excavation of "glory holes" for protection of subsea equipment. It is considered essential that additional study be made of the alternative methods for protection and the extent of risk involved. While it is accepted that a sufficiently large excavation will provide ultimate protection, insufficient data is available at this time to determine the cost effectiveness of the approach and the acceptability of alternatives, e.g., combined berms and excavations. Further, the contribution to be made by low profile wellhead equipment and caisson completed wells should be investigated.

SECTION 6

GAS AVAILABILITY

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6.0 GAS AVAILABILITY

6.1 BASIS FOR GAS AVAILABILITY

In accordance with the Study premises, it has been assumed that a maximum average of 250 MMSCFD may be produced from the Hibernia Field, mainly as associated gas.

This level of production is taken as the annual average daily plateau production rate after deductions for gas usage offshore and with allowances for overall production efficiency.

It must not be assumed that these gas quantities will definitely be available for export. Management of the reservoir may require gas re-injection for pressure maintenance in order to maximize recovery of the resource. Further, later in the life of the Field, reduced productivity may require gas lift thereby reducing gas availability.

It is considered reasonable to assume at this time that some gas re-injection may be required, at least in the early years of production. In summary, gas quantities may not become available for export until some years after production commences and at that time the quantities residual to offshore usage may not be economically recoverable.

For the purposes of this preliminary investigation, however, the facilities have been conceptualized including the capability to make 250 MMSCFD of gas available for export without prejudging what the real magnitude of such quantities may be.

Assuming 250 MMSCFD is the annual average rate, two questions arise:

i) What are the requirements for gas usage offshore, such quantities being assumed to be produced additional to the 250 MMSCFD; and

ii) What is the overall operational efficiency of the production system.

The question of fuel and other gas usage requirements offshore is dealt with in Section 6.2.

Overall operational efficiency is considered in Section 6.3.

6.2 FPF GAS USAGE REQUIREMENTS

6.2.1 General

Offshore, the fuel gas system of each production centre provides gas for uses which include:

- Power Generators - Applies to all centres
- Heating Systems - Applies to all centres
- Water Injection (Fuel gas stripping principle) - Applies to Avalon North and South only
- Flares - Pilots/Purging - Applies to all centres
- Inert gas generation (if used instead of nitrogen bottles) - Applies to all centres
- Gas Blankets, etc.
- Gas Reinjection/Export Compressors if turbine driven - Applies to Hibernia South only

The source of fuel gas on each centre and the characteristics of the overall system are discussed in Section 4.1.2. High pressure fuel gas is required principally for:

- Power Generation
- Gas Turbine Driver of Compressors
- Hot Water Expansion Drum Pressurization

Typical low LP source fuel gas users are:

- Sea Water Deaerators (if fuel gas stripping is proposed)
- Hot Water Heaters

- Inert Gas Generation
- Flare Pilots/Test Burner Pilots
- Flotation Unit

With respect to high pressure users, typical fuel supply pressures for turbines are:

Rolls Royce Avons	: 250 psig approx.
Other Types	: 140 psig to 200 psig depending on type

Liquid fuel for turbines, which will be needed for emergency uses or during fuel gas system or production shutdown, should be supplied at approximately 50 psig.

Turbine manufacturers will place limitations on feed gas quantity. The calorific value of the gas should, according to turbine manufacturers, be held to within 3% of the value used when setting up the fuel ratio value. A difference greater than this value may lead to difficulties with generator synchronization when switching from liquid to gas.

Sea water deaeration, required for water injection purposes, may be carried out either by gas stripping or by vacuum equipment. Gas stripping is applied to most water injection systems handling throughputs greater than 10,000 BWPD where natural or other suitable gas is available for use as fuel at low cost. Given the availability of gas offshore, and the principle of reducing topside equipment weight, gas stripping is considered a reasonable approach for the Hibernia Field.

Assuming gas stripping for deaeration, approximately 3 to 5 SCF/Bbl water will be required to meet a typical water injection quality.

6.2.2 Assessment of Fuel Gas Usage

Within the limits of this preliminary investigation, insufficient data is available on the conceptual topsides definition upon which to base a detailed electrical load analysis. A generalized approach has therefore been adopted based on similar facilities installed elsewhere.

For Avalon North and South the principal demand for fuel gas will be for water injection purposes while for Hibernia South, gas compression will be the principal demand.

For 150,000 BWPD water injection facilities power demand may be in the order of 26,000 hp, assuming discharge pressures in the order of 6,000 psig.

For 250 MMSCFD gas compression for re-injection purposes, power demand may be in the order of 33,000 hp, assuming discharge pressures in the order of 6,000 psig. Demand when compressing to 2,700 psig for sales gas purposes will reduce by approximately 50%, to, say, 15,000 hp.

Given the above major users, the overall power demand for each production centre in the peak year of production in order-of-magnitude terms, is estimated to be as follows:

Production Centre	Overall Power Demand
Avalon North	35,000 hp
Avalon South	38,000 hp
Hibernia North	12,000 hp
Hibernia South	53,000 hp (34,000 hp)
Gas Re-Injection (Gas Export)	
FIELD TOTAL DEMAND	138,000 hp (119,000 hp)

Subject to detailed definition of the power generation system, the type of gas turbine generators and other drivers adopted, and the calorific value of the fuel gas (which will vary depending on offtake point and operational mode) a generalized fuel gas demand of 0.30 to 0.37 MMSCFD per 1,000 hp may be assumed. This results in a field average fuel gas demand of between 41 to 51 MMSCFD when re-injecting gas or 36 to 44 MMSCFD when exporting gas. These data apply to the demand in the peak year of production.

It should be noted that fuel gas demand for power generation may be less during the build-up to peak production and during the years of production decline. Demand in these years will not however be directly proportional to production rate due to constant platform base load and the turndown limits on compressors, etc., which may require considerable recycle at reduced throughputs thereby maintaining demand.

During start-up of generators (including spares), fuel gas demand may double but this is transient and should not exceed the peak demand since during start-up it is unlikely that all users will be on-stream.

The above demand data assumes that gas is either wholly re-injected or wholly exported and does not account for simultaneous injection/export. The demand per peak stream day will be greater than the above and any increase in water injection throughput or gas quantities produced will have a significant effect on power demand. The average data is sufficient to assess the long term demand during the years of peak production, however.

For Avalon North and South, the low pressure gas system must be capable of supplying up to 0.75 MMSCFD each for fuel gas stripping associated with water injection. In overall terms up to 1.5 MMSCFD of low pressure gas may be required on these two platforms including blanket gas, pilots, etc., with 0.75 MMSCF required for low pressure gas usage on Hibernia North and South.

As a result of the above order-of-magnitude analysis, the field average peak year demand for fuel gas may be in the region of 46 to 56 MMSCFD when injecting gas or 40 to 49 MMSCFD when exporting gas, subdivided between production centres as follows:

	Average Fuel Gas Demand (MMSCFD)		
Production Centre	High Pressure	Low Pressure	Total
Avalon North	10.5-13.0	1.5	12.0-14.5
Avalon South	11.4-14.1	1.5	12.9-15.6
Hibernia North	3.6- 4.4	0.8	4.4- 5.2
Hibernia South - Injection	15.9-19.6	0.8	16.7-20.4
- (Export)	(10.2-12.6)	(0.8)	(11.0-13.4)
Peak Year Field Total			
- Injection	41.4-51.1	4.6	46.0-55.7
- (Export)	(35.7-44.1)	(4.6)	(40.3-48.7)

In accordance with the Study premises, the above gas is assumed to be produced over and above the 250 MMSCFD.

It is of interest to note, given its low gas production rate, Hibernia North may become gas deficient in later years if water injection load is maintained and require to "import" gas from other production centres. Depending on circumstances, a similar condition may also arise at Avalon South. Thus the Hibernia zone is the principal gas source for both reinjection and potential export in such years.

6.3 OVERALL SYSTEM OPERATIONAL EFFICIENCY

6.3.1 Introduction

An assessment of the overall efficiency of the production and transmission system must include consideration of the following interactive aspects:

- i) Well performance and maintenance
- ii) Subsea equipment reliability and maintenance
- iii) Downtime of the floating production facilities as the result of weather influencing:
  - * FPF ability to maintain production in severe conditions
  - * Oil storage system ability to remain on station and load oil
  - * Shuttle tanker system operations in terms of the ability to moor, remain moored and to load oil.
- iv) Downtime of the facilities as the result of planned maintenance activities
- v) Operational downtime of the process stream equipment and utilities

Each of the above factors contributes to the overall efficiency of the system, which in turn indicates the peak stream operating day production rates which must be achieved to maintain the annual average daily production rate.

It is important to bear in mind that during the early stages of design and engineering, detailed assessments will be made by the operator to determine the required peak stream day rate of production. This influences the number of wells required, the overall drilling programme (both prior to start-up and subsequently during the life of the Field) and also the design capacity of the process facilities.

In certain circumstances, as part of the regulatory approval procedure, a limiting rate of offtake may be imposed and/or a time limit set after which approval must be renewed if production is to continue. While the operator will bear such circumstances in mind, the facilities will normally be designed for optimum recovery of the resource. Particularly difficult for the operator to predict and handle are circumstances which may lead to changes in the offtake levels during the life of the Field. Operationally, it is important for the operator and the regulatory authority to establish a clear, common understanding of circumstances which lead to day-to-day fluctuations in the production rate. This is of particular importance in relation to the co-production of associated gas with crude oil which gives rise to a complex operational situation due to the often contradictory objectives of optimizing overall recovery, maintaining oil and gas sales contracts, minimizing flaring and meeting regulatory requirements. Within agreed limits, the regulatory requirements must include an operational margin to allow the operator some flexibility for inevitable day-to-day fluctuations in production characteristics. The common goal will be the achievement of the long term average production rate from the Field, preferably the annual average target.

Major failure of either the Floating Production Facilities or the gas transmission will cause significant loss of oil and/or gas production and is not accounted for here. Further, the requirement for major inspection and survey of the FPP's and storage vessels may require each structure to be dry-docked at phased intervals during its productive life, say every five years. The significant loss of oil/gas production which will arise is also not accounted for here.

6.3.2 Well Performance and Maintenance

On average, planned workover of each well will take place once every three years. Unplanned maintenance of the wells will be primarily related to unpredictable reductions in well productivity. The principal cause of such reductions will be the breakthrough of water into the producing wells or when reservoir pressure drops below the crude oil bubble point. As such circumstances arise a remedial programme would be scheduled for the particular well affected. Depending on the mechanism associated with the water entry the remedial programme will involve either one of, or a combination of, the following:

* wireline set bridge plug
* cement squeeze to isolate wet perforations
* artificial lift
* sidetracking existing holes to change bottom hole locations
* infill drilling to provide new bottom hole locations

It is envisaged that at least one, possibly two, dedicated semi-submersible workover/drilling rigs may be required in the Field to account for such circumstances, depending on the number of wells. It is assumed that production can continue from wells adjacent to the well being worked-over thus minimizing production losses.

For a fixed drilling/production platform planned and unplanned drilling/workover losses may be in the order of 5% of peak oil availability. Due to the requirement for floating workover rigs subject to weather downtime this allowance may increase to, say, 10%.

6.3.3 Subsea Equipment

Considerable reliance is placed on the successful and continued operation of the extensive subsea equipment utilized in the development concept adopted for Study purposes. This equipment includes:

- cluster manifold centres;
- riser manifold bases;
- satellite wellheads.

This equipment will require regular planned inspection and maintenance utilizing surface vessels and diving spreads which are weather sensitive. It is likely that this work would be undertaken by the drilling/workover rigs available in the Field. There is no current experience available to estimate the possible effect on production of such an extensive subsea development and an allowance in the order of 10% to 20% overall downtime should be considered at this time, although effective design may reduce this to, say, 5%.

6.3.4 Weather Downtime

In addition to the effect of weather on the drilling/workover rigs and support/service vessels, sea state will have a significant operational influence on the various floating production and storage vessels employed.

.1 Floating Production Facilities

The limiting factor for the four semi-submersible production centres will be the production riser.

Typical design targets for limiting operational sea states for semi-submersible production platforms, together with possibly more realistic operational "trigger" limits given the design target, are as follows:

	Max. Wave Height Limits Design	Max. Wave Height Limits Operational Triggers
1. Full-Operation - Riser Connected, and producing	50 ft.	35 ft.
2. Riser Survival - Riser Connected, Production Shutdown	60 ft.	45 ft.
3. Central Riser Column Survival - for non-integral risers	90 ft.	50 ft.

The realistic limits compared to design are likely to arise in practice as a result of:

- * generally lower weather thresholds
- * longer riser shutdown and retrieval times
- * longer riser re-installation and testing periods
- * greater than envisaged risk of physical damage
- * unforeseen operational difficulties

For example, the Buchan riser, which is a non-integral type, requires a period of 48 hours to retrieve and retrieval must be completed while rig heave is less than 16.5 ft. This implies a maximum wave height in the order of 40 ft. Reconnection of the Buchan riser is limited to 3.3 ft. heave which exemplifies the fact that overall downtime is not simply predicted by limiting operational sea state. Further, where diver assistance is required, limiting sea states for diver deployment may be as follows:

Surface Diving	:	5 ft. to 8 ft. maximum waves
Saturation Diving	:	10 ft. to 14 ft. maximum waves

Effective downtime will have much to do with the quality, accuracy and reliability of weather forecasting and the prediction of imminent sea states which may arise as a result of such forecasts. Regular forecasts at, say, 6 hour intervals will be required. The operator will consider such forecasts and the following hypothetical sequence may be envisaged in accordance with possible operating procedures:

i) The riser will be pulled when waves greater than the design/realistic operational limit are forecast.

ii) Retrieval will be within 6 hours (for an integral riser) preceded by a 12 hour shutdown and waiting period during which time the riser is depressurized and lines flushed or gas-freed. This time would increase if there is also a need to flush in-field flowlines, well-bores, etc., due to crude pour point problems.

iii) There will be a small number of false alarms per year.

iv) The riser will be pulled occasionally for reasons not associated with weather.

v) There will be a small number of emergency disconnects as a result of failure to predict excessive sea states.

vi) Reconnection will be undertaken when calculated maximum wave height is below the design/realistic reconnection/diving limit and the weather forecast is good for at least three days.

vii) Reconnection will be achieved in 12 hours, followed by 12 hours to test and pressurize system, followed by 12 hours build up to full production

Given a riser retrieval criterion similar to Buchan, i.e., 40 ft. maximum wave height, a forecast of seas of significant wave height 20 ft. may initiate the riser retrieval sequence. Even in winter at the Hibernia location less than 8% of significant wave heights are greater than 20 ft.; less than 0.1% in mid-summer. Insufficient forecasting data is available to predict the frequency of occurrence of forecasts of waves greater than 40 ft. It is envisaged that this may arise several times a year. If it is assumed that on average a storm will last four days before seas calm sufficiently to initiate reconnection, then the following overall downtime due to weather may be hypothesized:

Event	Downtime
Actual Storms, Riser Pulled, say, 4 No.	4 x 6 days = 24 days
False Alarms, Riser Pulled, say, 4 No.	4 x 4 days = 16 days
Production Shutdown, Riser Not Pulled, say, 4 No.	4 x 2 days = 8 days
	48 days

The above represents an overall shutdown due to weather of only 13% over a full year. Adding reasonable contingencies to the above may lead to shutdown in the range of 15% to 20% over a year. Downtime less than 15% is not readily envisaged but shutdown greater than 20% may arise depending on selected design of semi-submersible, riser and riser handling system. For example, the Argyll riser, a non-integral type, was pulled 28 times for weather in the first two years of operation.

In addition, the riser will be pulled occasionally either for maintenance or for access to the riser manifold base for inspection and maintenance purposes. Also, should a storm be sufficiently severe for emergency disconnect to be initiated and/or the FPP be driven off station, increased shutdown will occur.

.2 Oil Storage/Mooring/Loading System

The other components of the system influenced by weather are the oil storage tanker and the shuttle tanker mooring loading system.

Typically, for a high capability shuttle tanker/mooring/loading terminal such as an articulated column, capable of handling tankers between 70,000 ton dwt. to 120,000 ton dwt., the following operational limits may apply with specially dedicated shuttle tankers capable of self-mooring to the terminal:

	H(sig)	H(max.)
Maximum Mooring Conditions:	10 ft.	20 ft.
Maximum Loading Condition:	18 ft.	36 ft.
Maximum Condition to Remain Moored, Not Loading:	27 ft.	54 ft.

Not withstanding the above capabilities, offshore mooring/loading systems without buffer storage at exposed locations cannot be expected to maintain better than 25% annual efficiency. Buchan, which has only 4,500 bbl storage for surge/tanker changeover purposes, is predicted to operate at 35% annual efficiency using a catenary anchor leg mooring (CALM).

In general terms, adding 7 to 10 days storage to the system is normally expected to improve efficiency to better than 90% at exposed locations.

It may be noted, however, that tanker mooring/loading terminals installed at exposed locations should be expected to suffer occasional major shutdown for repairs/replacement. For fields with relatively high storage volumes and production rates, it is advisable to install duplicate mooring/loading terminals. Allowance has been made in the cost assessment carried out for Study purposes for 7 days storage in two storage tankers, each fitted with an over-stern mooring loading system for use in moderate weather, together with two remote mooring/loading terminals.

With such a system for Hibernia, 10% downtime due to the effect of weather on the storage/loading system may be achievable. More precise predictions may be obtained through the use of offshore storage/loading simulation programs.

Additional downtime may arise due to fog, pack ice, etc., such that, at this time, shutdown of the storage/mooring loading system may be envisaged to be in the order of 15% annually.

At such a level, the limiting component of the overall system is considered to be the FPP and its riser.

It should be noted that the individual components of downtime are not directly additive but are linked by the probability of simultaneous or separate occurrence. Further, during downtime of one component, useful advantage may be gained by carrying out preventive maintenance or other components, if conditions are suitable.

6.3.5 Topside Facilities

The planned drilling/workover programme establishes the peak oil/gas availability at any time, i.e., the maximum potential supportable by the reservoir through the producing wells. Given annual average production targets, a required offtake level will be estimated taking into account production deferment and/or losses for any reason, including:

- the planned drilling/workover programme;
- planned shutdown of the process facilities for topsides or platform maintenance;
- voluntary reductions in oil production during planned maintenance or unplanned shutdowns of equipment downstream or outside the oil plant, e.g., gas re-injection plant;
- unplanned shutdown of the oil plant;
- other unplanned events which influence oil production, e.g., overrun on maintenance schedules;
- throughput limits on process equipment.

The actual off-take level will then be adjusted in practice to achieve the annual average taking into account deviations from the expected planned or unplanned events. Within limits, it may be possible to offset losses on any one platform by increased production on other platforms.

Given the peak oil/gas availability and external events which cause planned or unplanned shutdowns of the oil plant and downstream equipment, it remains to predict the unplanned shutdown of the process plant.

For each production centre, although a single train concept has been employed for the oil/gas separation plant, the component parts of the system are relatively simple. Uptime of the oil/gas plant may therefore be in the order of 90% to 95% for all time between shutdowns arising from planned events or unplanned external events.

Uptime depends on the combination of equipment reliability, process conditions falling outside operational limits and operator error.

Within this uptime, it should be remembered that a number of different process operational modes may arise, e.g., variations in separator operating pressure to provide fuel gas when the fuel gas system is shutdown. The different operating modes will give rise to different relative quantities of oil and gas production. Further, within each mode, real time variations will arise within process limits thereby further influencing effective production.

Given the dual train philosophy adopted for the gas re-injection/export equipment, reliability of these systems should be high, in the range of 92% to 96%.

6.3.6 Gas Transmission System

The gas transmission system as adopted for Study purposes, is intrinsically simple with no intermediate compression. Within normal operating limits uptime should be better than 98%.

This does not include for shutdown due to the process facilities outside the battery limit of the onshore gas reception facilities being unable to accept incoming gas, resulting in either flaring, onshore or offshore, or production shutdown.

6.4 GAS QUANTITIES POTENTIALLY AVAILABLE FOR EXPORT

The basis for the Study is that facilities should be provided to either re-inject and/or export an annual average gas quantity of 250 MMSCFD produced in association with 280,000 BOPD.

This premise has been maintained, notwithstanding any anomalies which arise concerning development of the reservoir in terms of overall production rates or relative rates between production centres. Such anomalies are discussed in Section 3.1 but do not detract from the main purpose of this preliminary investigation, i.e., the feasibility and cost of integrating the potential for exporting gas within the overall development given the level of production stated. Considerable variation in production, say, greater than 10% to 20%, would require a re-evaluation of the concept.

As stated earlier, it is re-emphasized that 250 MMSCFD is simply a potential figure, and must not definitely be considered available for export either in total or in part without greater definition of reservoir performance or the need for gas re-injection for pressure maintenance.

Comment may however be made on the overall level of gas which must be produced to make 250 MMSCFD potentially available.

In the first instance fuel gas at a Field average peak year level of 46 to 56 MMSCFD may be required when re-injecting gas. Average annual levels of produced gas must therefore be in the order of 296 to 306 MMSCFD to meet this demand. This implies a "required" peak year Field average separator GOR of approximately 1,057 to 1,093 to provide 250 MMSCFD plus fuel gas demand. Given this same GOR when producing for export, i.e., wholly associated gas production, a marginal increase, say 1% to 2% over 250 MMSCFD, will arise in the gas quantities available for export due to less fuel gas demand.

Secondly, overall system downtime as a result of planned and unplanned events may be envisaged to be in the region of 20% to 25%. This is an estimate only and would require confirmation or revision as the result of a detailed operational analysis of the preferred development concept.

The production limit of the process equipment must therefore be at least 1.25 to 1.33 times the annual average production rates. In terms of oil production this implies a level of 350,000 BOPD to 373,000 BOPD. Actual design oil capacity for existing developments compared to average throughput typically ranges from +10% to +100% depending on the operator's knowledge of the resource and preferred design philosophy. For example, the Buchan Field has a capacity of 70,000 BOPD to deliver 45,000 BOPD average and a predicted overall downtime of 35%.

The weight and cost assessments carried out for Study purposes include adequate contingencies to allow for peak as compared to average throughput.

Given the "required" peak year Field average separator GOR's for Hibernia of 1,057 to 1,093 defined above, gas production rates corresponding to the peak stream day oil rates given above may be in the order of 370 MMSCFD to 408 MMSCFD.

Again, due to the lower fuel gas demand for export compression, gas quantities potentially available for export may increase, given wholly associated gas production. For the oil rates given above, taking into account overall downtime and the range of fuel gas demand, gas quantities potentially available for export in the peak year of production may be in the order of 330 MMSCFD to 360 MMSCFD. These data take no account of production phasing as regards gas injection/export nor of the fact that both associated and non-associated gas may be produced, the non-associated gas being a flexible quantity not wholly dependent on oil production. Further, no account has been taken for any possible increase in water injection capacity above 300,000 BWPD which may be required to maintain reservoir pressure.

It is again emphasized that the above gas quantities are potential only, and may not necessarily become available for export.

The capability to handle the high oil and gas levels indicated above has not been allowed for in the topside facilities weights developed in Section 5.2 which are based on the average annual rate of 280,000 BOPD and an average stream day rate of 320,000 BOPD.

The capacity of the 24" gas pipeline transmitting "dense phase" gas is 430 MMSCFD with adequate margins for liquid drop-out in the line and is thus capable of handling the quantities of gas considered.

SECTION 7

GAS TRANSMISSION SYSTEM

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7.0 GAS TRANSMISSION SYSTEM

7.1 PIPELINE TERMINATION AND ROUTING

Previous studies by others concerning pipelines from Hibernia to Newfoundland have considered landfalls either at Bay Bulls or Cape Race/Trepassey Bay. Bay Bulls represents the most direct line to shore (approximately 195 miles) while the Cape Race/Trepassey Bay routes pass the Virgin Rocks and have a total, direct length in the order of 220 miles.

In general, termination of oil pipelines has been the Come-By-Chance refinery (currently mothballed) requiring a landline from the submarine pipeline landfall.

For the purposes of this Study, Long Harbour was assumed to be the termination of the gas pipeline since it is a designated industrial development zone. At present there are no gas processing facilities available at Long Harbour (or elsewhere in Newfoundland) and delivery of gas will require a new plant. Such processing facilities are not included in the scope of the Study.

The direct submarine route to Bay Bulls has a considerable length through the Avalon Channel where pipeline burial to any significant extent is not considered feasible, possibly 130 miles. However, Mobil has estimated that a direct southerly route, which may have less exposed pipe, may be in the order of five times more susceptible to pipeline damage from iceberg scour due to its shallow water depth and that pipeline rupture may be anticipated several times a year. The level of risk is controversial and insufficient information is available to quantify the acceptable risk at this time. The question of such risk, and the feasibility of trenching through the Avalon Channel, is therefore excluded from this preliminary investigation.

Based on soils information available to the Petroleum Directorate, however, an even more southerly route, generally south of 46°15'N, was considered to offer greater potential for pipeline protection due to the reduced width of the Avalon Channel and the increased occurrence of surficial seabed soils which may at least offer the potential for conventional trenching. Conventional trenching to, say, 3 to 6 ft. cover may not offer any significant reduction in risk, however.

In the early stages of the Study, two alternative submarine pipeline landfalls were considered:

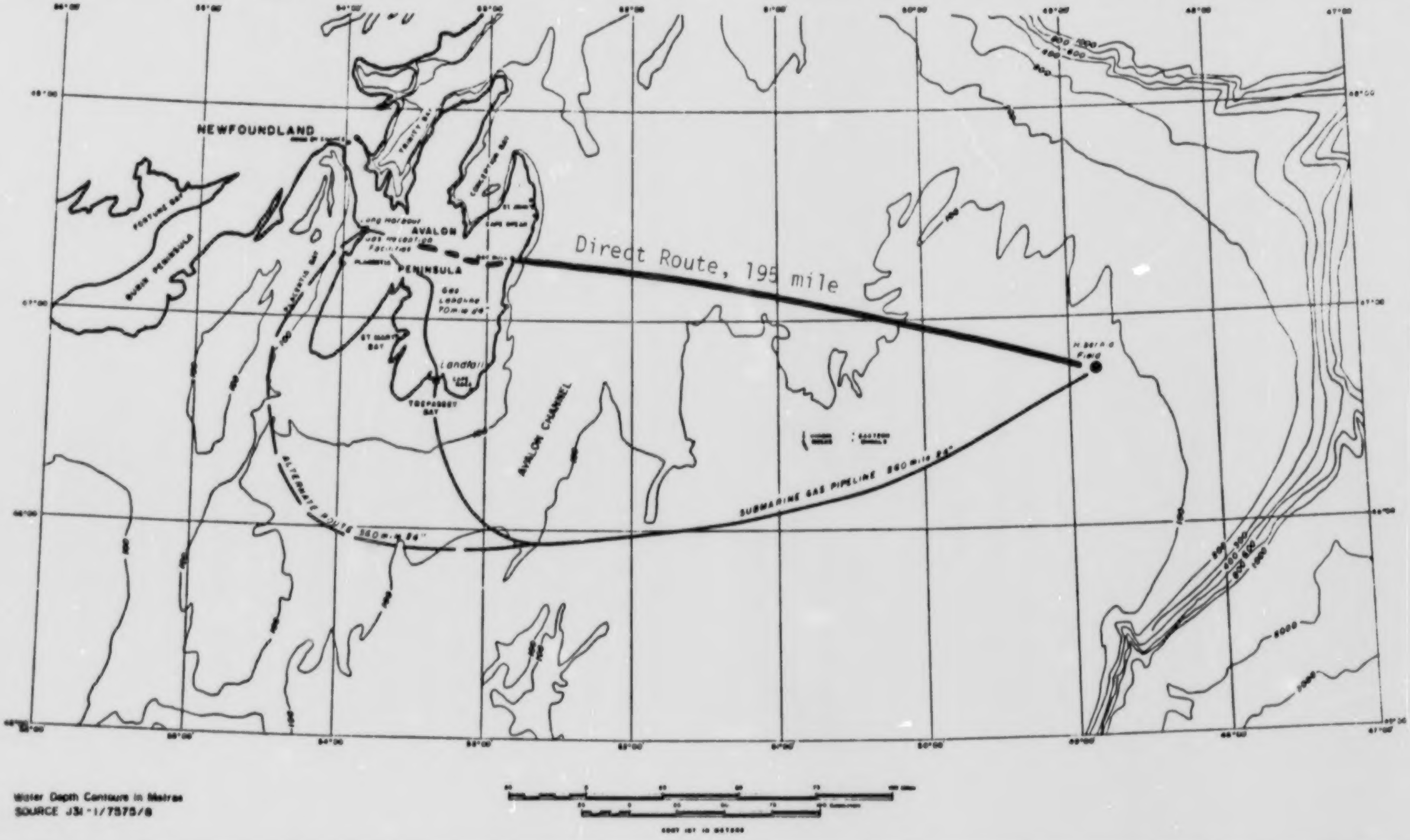
i) Trepassey Bay (requiring an onshore pipeline of length approximately 70 miles to Long Harbour).
ii) Long Harbour (wholly submarine pipeline).

The emphasis of the main Study was directed towards a southern route. Subsequent to completion of the main Study, however, brief consideration has been given to the more direct route to Long Harbour via a Bay Bulls landfall, a route requiring a submarine line length of approximately 195 miles and an onshore line length of approximately 55 miles.

These routes are indicated on Figure 7-1. Maximum advantage was taken for potential trenching of either pipeline in the Cretaceous/Tertiary seabed zone delineated by the Petroleum Directorate and shown on Figure 7-2 (Reference J31-1/7575/8).

With respect to the two alternative southern routes, the submarine line lengths to either Trepassey Bay or Long Harbour were taken to be 260 miles and 360 miles respectively.

HIBERNIA FIELD GAS PRODUCTION STUDY - BATHYMETRY AND POSSIBLE PIPELINE ROUTES


NEWFOUNDLAND
AVALON
PENINSULA
Long Harbour
Gas Reception Facilities
Gas Landline 70 mile 26"
St Mary's Bay
Landfall
Trepassey Bay
Trinity Bay
Conception Bay
Placentia Bay
Fortune Bay
Burin Peninsula
AVALON CHANNEL
Direct Route, 195 mile
Hibernia Field
SUBMARINE GAS PIPELINE 260 mile 26"
ALTERNATE ROUTE 360 mile 26"
100
200
400
600
800
1000
2000
3000

Water Depth Contours in Metres
SOURCE J31-1/7575/8

Figure 7-1

/7575

The longer route has an apparent advantage in terms of potential burial through the Avalon Channel but will require installation in considerably deeper water depths compared to the Trepassey Bay route, say, 620 ft. in Placentia Bay versus 510 ft. for the shorter route.

Further, the seabed in Placentia Bay is sloped steeply transversely to the pipeline route which will give increased difficulties in making a landfall. Conversely, the Trepassey Bay shore approach is reasonably gentle over mixed rock/sand/gravel, the landfall site apparently presenting no difficulties.

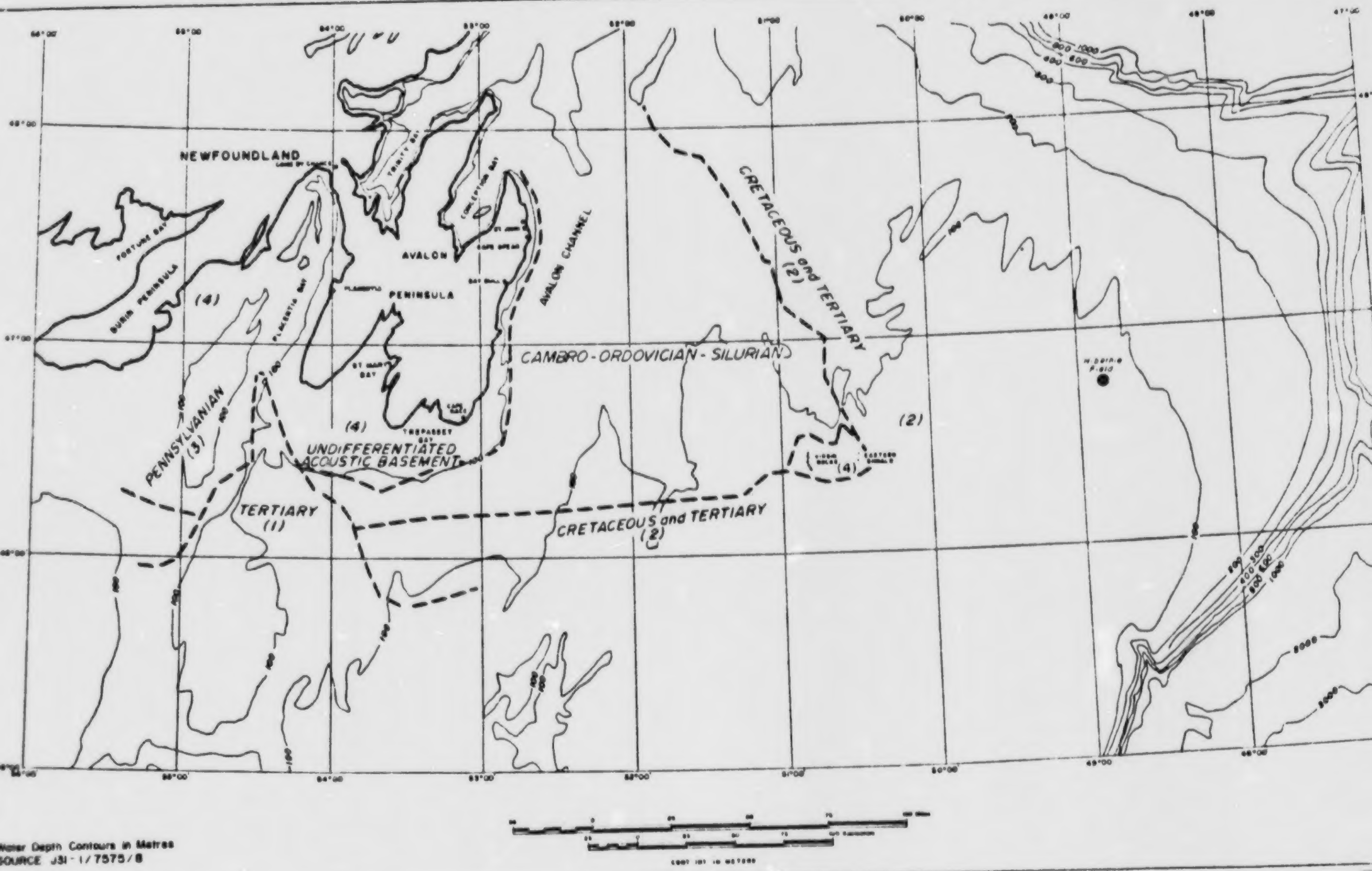
Other landfalls further east of Trepassey Bay do not offer such good approach conditions. Further, it is understood that a significant length of coastline between Drook and Cape Race may become a restricted area of geological interest.

At the level of investigation carried out in this Study, it is not possible to differentiate between the two proposed routes in terms of risk of pipeline rupture due to iceberg scour, even if relatively deep trenching by conventional methods, say, 12 ft., were to be proved feasible.

As regards relative cost between the two routes, historical costs for offshore versus onshore pipelining indicates that onshore pipelining, even over the difficult terrain anticipated on the Avalon Peninsula, will be the less costly.

As a result of the above considerations, the longer of the two southern routes was rejected in favour of the landfall at Trepassey Bay with a landline to Long Harbour. Information relating to the northern route is provided in Section 7.9.

HIBERNIA GAS PRODUCTION STUDY - BEDROCK GEOLOGY (TERTIARY AND OLDER)


NEWFOUNDLAND
FORTUNE BAY
BURIN PENINSULA
(4)
PLACENTIA BAY
TRINITY BAY
CONCEPTION BAY
AVALON
PENINSULA
ST. MARY'S BAY
TREPASSEY BAY
AVALON CHANNEL
PENNSYLVANIAN
(3)
(4)
UNDIFFERENTIATED
ACOUSTIC BASEMENT
TERTIARY
(1)
CAMBRO-ORDOVICIAN-SILURIAN
CRETACEOUS and TERTIARY
(2)
CRETACEOUS and TERTIARY
(2)
(2)
(4)
Hibernia Field
100
200
400
600
800
1000
2000
3000

Water Depth Contours in Metres
SOURCE J31-1/7575/8

Figure 7-2

7.2 ALTERNATIVE SYSTEM ARRANGEMENTS

7.2.1 Intermediate Compression Facilities

With reference to the southern route adopted for Study purposes, Hibernia - Trepassey Bay - Long Harbour, a number of alternative arrangements may be envisaged:

- i) The entire pipeline, submarine line and landline, may be designed as a single length between Hibernia and Long Harbour; or
- ii) An intermediate compression station may be installed at the Trepassey Bay landfall offering the possibility of reduced pipeline diameters at the expense of additional compression cost; or
- iii) An intermediate compression station may be installed part way along the offshore line possibly in conjunction with (ii) above; or
- iv) Pressure regulation at Trepassey Bay may permit a reduction in pipe wall thickness at the expense of increased two-phase flow in the landline.

The inclusion of an offshore compression station would require an additional support structure together with full facilities simply to support compression. This would be an expensive option for reducing line diameter and is not considered to be economic. This is particularly so since sufficient compression capability is available at Hibernia at no additional cost above that required for injection facilities. Further, inlet pressures with such equipment indicate that, with moderate line diameters, no liquid drop-out is likely to occur in the submarine gas pipeline, except during shutdown.

The suggestion has been made in the past that the Virgin Rocks be used as an intermediate station. This is not considered worthwhile for gas pipeline transmission purposes alone. However, should the Virgin Rocks ever be considered for other additional purposes, e.g., an offshore safety station, then integration of such uses with compression may be reviewed.

Inclusion of a compression station or pressure regulation at the Trepassey Bay landfall should be considered during basic engineering of the system. Without detailed study, it is not possible to quantify the differential economics of including compression or regulation at the landfall. The diameter or wall thickness of the landline may be reduced but considerable additional equipment would be required at the landfall, i.e.:

* slug catcher
* pig receiver
* liquids handling system
* compression
* flare/vent system
* utilities, etc.

Some equipment duplication will arise between the landfall and the gas reception terminal at Long Harbour. It is considered unlikely that compression at Trepassey Bay would prove economic but this may only be verified by detailed study. With pressure regulation, savings may be made on the 70 miles of line pipe through wall thickness reduction but additional landfall equipment will be required and the system would be operationally more complex.

In consideration of the above, and adopting the premise of maintaining simplicity within the overall system, it was assumed that the pipeline be conceptualized as a single length between Hibernia and Long Harbour. It is emphasized that more detailed study of the above alternatives may modify this assumption. In such studies, consideration may be given to the removal of NGL at Trepassey Bay for separate disposal/transhipment as compared to transmitting the gross gas to Long Harbour. Such an arrangement would be analogous, to some extent, with the St. Fergus terminal in Scotland which serves both the Frigg and Brent Fields.

7.2.2 Multiple Pipeline Systems

It is of interest to consider whether the use of multiple pipeline systems, rather than a single transmission line offers any benefits for the Hibernia development, as regards security of supply of gas to shore given the risk of pipeline scour damage.

Assuming that a single 24" line is sufficient for transmission, multiple lines capable of handling the same capacity of gas might be sized as follows:

1 x 24" = 2 x 18" = 3 x 16"

Both material and construction costs will increase through the use of multiple lines, particularly when the lines would need to be laid over widely different routes in order to increase the apparent security of supply. It is considered that such increases over the cost of the single line may be in excess of 50% for the double lines and 100% for the triple lines. For at least double the cost, however, the single lines may simply be duplicated. Alternatively the same diameter line twinned over exposed sections of the route with suitable subsea "Y" branches, valves and pig diverter equipment.

In subjective terms, there is some statistical benefit to be gained as regards security of supply in installing multiple lines or even duplicating the single line system.

Any subjective reduction in risk is difficult to quantify since in the first instance much controversy exists concerning the inherent risk of a single line, and in the second it must be assumed that the single line would be installed along the optimum route as regards natural protection from seabed features (as would one of the multiple lines). Further, the risk of rupture due to more conventional reasons, e.g., anchors, is increased with the use of multiple lines. The overall risk of rupture is therefore likely to be increased through the use of multiple lines but security of supply is likely to improve but at considerable initial cost.

It is difficult to envisage, at this time, multiple pipelines being worth the additional project effort, capital and operating cost, compared to the optimally routed single line, in terms of relative risk. Absolute risk levels remain undefined at this time but if the risk is high the relative economics of twinning the main line over lengths of high risk may be investigated.

7.2.3 Flexible Lines and Reel Barges

Flexible pipelines (e.g., Coflexip) are not available in long lengths of the diameter and service capability required to meet the main gas pipeline requirements of the Hibernia Field. They find their main application offshore as short in-field flowlines or transfer lines, including use as risers and spool pieces.

Reel barges are claimed to be capable of laying up to 16" diameter lines although only 12" has been laid to date.

Neither approach has therefore been adopted for main gas pipeline use. However, their use for in-field lines should be considered.

7.3 CONCEPTUAL SYSTEM CONFIGURATION AND SPECIFICATION

7.3.1 General System Description

The conceptual gas pipeline system configuration adopted for Study purposes is illustrated in Figure 7-3.

Gas at medium pressure (say 1,200 psig) will be dehydrated prior to entering the first stage of the centrifugal compression train used for gas injection. (The dehydration unit will be switched out when gas is compressed for injection purposes only).

Following compression to (say 2,700 psig) the gas would be metered prior to transmission. The gas would pass from the export header on the deck of the FPP to the riser via jumper hoses. Several lines may be necessary in the riser to accommodate the gas quantities exported and if this is so then the gas from each line would be manifolded in the Riser Manifold Base prior to flowing to the main submarine gas pipeline.

In the event that the riser system cannot be sphered or pigged, a seabed pig/sphere launching system would need to be developed since liquids will need to be displaced from the main line at intervals.

The gas would flow directly to Long Harbour via the landfall without intermediate compression, a distance of 330 statute miles.

Liquids dropping out in the line would be removed periodically by means of spheres or displacer pigs. Since liquid drop-out is most likely to arise in the landline as pressures fall below, say, 1,500 psig, an additional pig/sphere launcher may be installed at the landfall thereby reducing the frequency for running pig/spheres through the offshore line.

Liquid slugs would be removed at the Long Harbour gas reception facilities which would include liquid storage and some means of its disposal. Untreated gas would then flow beyond the battery limit of the gas reception facilities to an undefined gas user or processing facility.

7.3.2 Pipeline Physical Characteristics

The pipeline will be defined by the following physical characteristics:

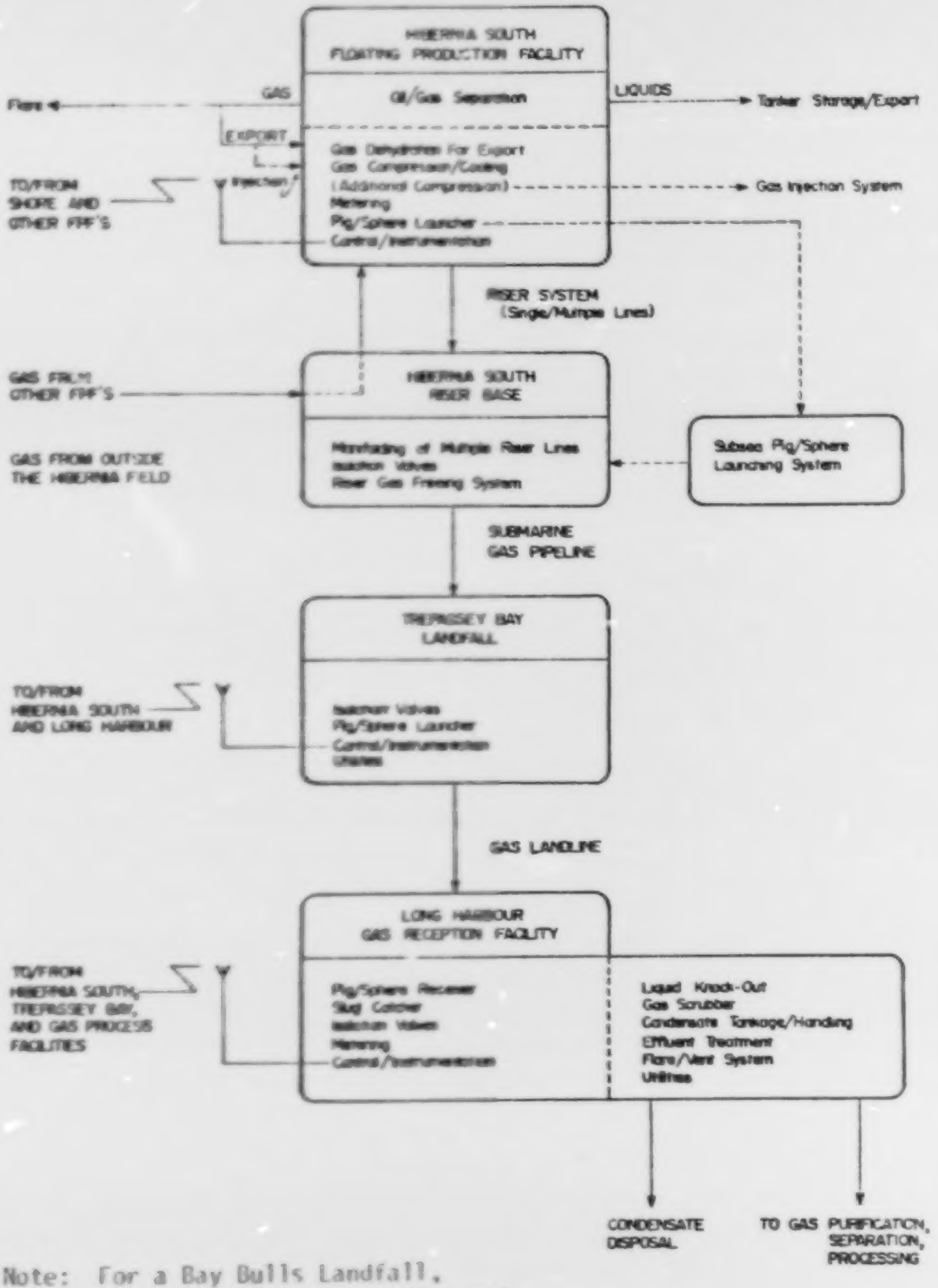
* diameter
* wall thickness
* material properties
* specific gravity

Diameter is generally selected as a result of an economic optimization of overall system cost in which reducing diameter (and hence pipeline costs) may be offset by increasing compression requirements (and hence boosting costs). Both capital and operating costs must be considered and diameter may be constrained by manufacturing and installation limitations.

Wall thickness depends on the ability to withstand internal pressure during operation, as well as loads imposed during installation. A corrosion allowance may also need to be included.

Material properties determine the mechanical and structural behaviour of a pipe of given diameter and wall thickness and also influence weldability. Material properties thus have significant influence on pipe laying operations and limitations.

HIBERNIA FIELD - ELEMENTS OF THE GAS TRANSMISSION SYSTEM


HIBERNIA SOUTH
FLOATING PRODUCTION FACILITY
GAS
Flare
Oil/Gas Separation
LIQUIDS
Tanker Storage/Export
EXPORT
Injection
Gas Dehydration For Export
Gas Compression/Cooling
(Additional Compression)
Metering
Pig/Sphere Launcher
Control/Instrumentation
Gas Injection System
TO/FROM
SHORE AND
OTHER FPF'S
RISER SYSTEM
(Single/Multiple Lines)
GAS FROM
OTHER FPF'S
HIBERNIA SOUTH
RISER BASE
Manifolding of Multiple Riser Lines
Isolation Valves
Riser Gas Freeing System
GAS FROM OUTSIDE
THE HIBERNIA FIELD
Subsea Pig/Sphere
Launching System
SUBMARINE
GAS PIPELINE
TREPASSEY BAY
LANDFALL
TO/FROM
HIBERNIA SOUTH
AND LONG HARBOUR
Isolation Valves
Pig/Sphere Launcher
Control/Instrumentation
Utilities
GAS LANDLINE
LONG HARBOUR
GAS RECEPTION FACILITY
TO/FROM
HIBERNIA SOUTH,
TREPASSEY BAY,
AND GAS PROCESS
FACILITIES
Pig/Sphere Receiver
Slug Catcher
Isolation Valves
Metering
Control/Instrumentation
Liquid Knock-Out
Gas Scrubber
Condensate Tankage/Handling
Effluent Treatment
Flare/Vent System
Utilities
CONDENSATE
DISPOSAL
TO GAS PURIFICATION,
SEPARATION,
PROCESSING

Note: For a Bay Bulls Landfall,
the overall system configuration
will be similar

Figure 7-3

With specific reference to the submarine line, hydrostatic and buckling loads are imposed during installation. Water depth is an important factor in determining such loads. The specific gravity of the installed pipe must be sufficient to provide negative buoyancy, and hence contribute to on bottom stability, when full of air. A concrete weight coat will be required for on-bottom stability and protection. Burial may also be required in areas of high marine activity, bottom currents or wave action. For the landline, under particular circumstances, e.g., river crossings or marshy areas, additional weight may also be required, usually supplied by separate weight blocks.

7.3.3 Pipeline Specification

.1 Line Sizing

The performance of the pipeline has been assessed given a number of conditions as follows:

i) Offshore inlet pressure of 2,700 psig (ANSI 1500 valves and fittings required).

ii) Offshore inlet pressure of 2,200 psig which is the Maximum Allowable Working Pressure of ANSI 900 valves and fittings.

iii) Outlet pressure of 1,500 psig for "dense phase" gas transmission.

iv) Outlet pressure of 1,200 psig for "dry" gas transmission.

v) Outlet pressure of 500 psig to indicate the ultimate capacity, a lower pressure not being possible due to erosion of the pipe wall by liquid droplets at the high velocities reached.

Operating at between 2,700 psig and 1,500 psig, a 20" O.D. pipeline, 330 miles long would just have the capacity to carry 250 MMSCFD but without any spare capacity. A 24" O.D. pipeline is therefore the minimum recommended line size. The 24" line exhibits the following capacity limits:

Southern Route - 330 Miles

	Inlet Pressure, psig	
Outlet Pressure, psig	2,700	2,200
1,500	430 MMSCFD	310 MMSCFD
1,200	460 MMSCFD	360 MMSCFD
500	510 MMSCFD	410 MMSCFD

Thus a 24" O.D. pipeline could handle 430 MMSCFD of "dense phase" gas and 460 MMSCFD of "dry" gas in the peak operating regime, with an ultimate "dry" gas capacity of 510 MMSCFD. Reducing maximum line inlet pressure to permit the use of ANSI 900 valves and fittings (i.e., to 2,200 psig) reduces the line capacity by approximately 100 MMSCFD.

The 24" O.D. line therefore has adequate capacity to handle peak flows based on an average throughput of 250 MMSCFD. Any further increase in line diameter will depend on operator preference and the future potential for the transmission of additional quantities of gas.

.2 Wall Thickness

Assuming the use of API 5LX 60 material, the 24" O.D. pipe will require a 0.75" wall thickness to operate at 2,700 psig.

The above specification has been developed using the typical "dry" and "dense phase" gas compositions discussed in Section 4.4. The specification is therefore indicative only based on the limited data available at this time.

Given the conceptual arrangement of the system, the 24", API 5LX 60, 0.75" wall thickness pipe will extend from Hibernia through to Long Harbour. Intermediate compression at Trepassey Bay may reduce wall thickness as well as diameter. It may be noted that 24", 0.75" w.t. line pipe is not currently available from Canadian pipe mills and would be an international supply item. Pressure regulation at Trepassey Bay would reduce wall thickness.

.3 Weight Coat

The 24" line pipe will require a concrete weight coat for on-bottom stability during construction and installation. Its thickness cannot be finally established without detailed analysis of total combined bottom currents, etc., derived from a current survey along the pipeline route and definition of design wave condition. In addition to providing on-bottom stability, however, the concrete may be relied upon to provide significant protection from impact by trawl boards and small anchors.

Considerable engineering, design and analysis effort was expended by Shell/Esso during the design of the Brent FLAGS line in the North Sea to determine the real value a) of the weight coat, and b) of trenching the pipeline. This line is laid water depths down to 540 ft. (equivalent to the Avalon Channel) and crosses several major fishing banks. The main conclusions arising from the research programme undertaken by Shell/Esso are quoted as follows:

> "* pipeline stability will be obtained by concrete weight-coating alone in the deep water sections (over 70% of the route),
>
> * the high strength concrete coating will tolerate repeated contact by the heaviest fishing gear,

- trenching would provide no additional protection to the pipeline in the deep water section and would increase the risk of damage to fishing gear,
- trenching in shallow water -- needed for additional stability -- will prevent contact with fishing gear because natural backfill will occur,
- no known trenching technique will protect the pipeline against large anchors."[1]

Deep water in the above conclusions relates to depths over 330 ft., i.e., deeper than the Grand Banks. Similar investigations would need to be undertaken with respect to the Hibernia pipeline prior to finalization of the design. World-wide, however, the majority of pipelines are trenched.

However, given the advances in weight coat design as a result of the FLAGS programme, weight coat alone may well provide adequate protection against trawl boards and small anchors in the Hibernia application.

Subject to detailed evaluation, a typical weight coat thickness for 24" pipe is in the order of 2" to 2-1/2" with increased thickness as required in zones of high fishing activity, strong currents and at the shore approach. The specification of the weight coat

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1. Broussard, D.E., Kittan, D.K., et al, "FLAGS Gasline-Design for Seabed Safety and Stability, European Offshore Petroleum Conference, London, 24-27 October, 1978.

determined during detailed design must be sufficient to maintain stability for empty, unburied, pipe in the worst combined conditions of current and design storm wave, e.g., 50 yr./100 yr.

.4 Corrosion Protection

Typically, submarine pipelines are protected from external corrosion by an anti-corrosion coating and a sacrificial anode system. Internal corrosion should be minimal due to the gas being dehydrated and having low proportions of corrosive elements. Internal coating or a corrosion allowance should not be required.

The majority of submarine pipelines throughout the world use either coal-tar or asphalt based coating although "thin film" powder epoxy coatings are gaining popularity. Coal-tar or asphalt wrappings provide proven and satisfactory protection where the line temperature is cool but examples of gas pipeline "creep" have occurred due to the coal-tar softening and disbonding between the pipe wall and the concrete coating at elevated temperatures near the exporting platform. Such temperatures may be reached in normal operation or when the coolers shutdown. Creep is cumulative with every significant start-up/shutdown sequence and must be handled either by pipeline anchoring or inclusion of expansion loops or dog-legs at the platform end. Near Hibernia South therefore either epoxy or neoprene coatings may be used.

Riser piping will also require protection, the choice of coatings depending on the extent of maintenance achievable during operation.

A sacrificial anode corrosion protection system will be required with probable anode spacing in the range of 300 ft. to 500 ft. (to be determined during detailed design). Zinc or aluminum anodes may be used with aluminum currently being preferred by the industry.

For the landline, either conventional wrapping, or "thin film" powder epoxy coatings may be used. The pipe may also be internally coated. The landline should be electrically isolated from the submarine line.

.5 Summary of Specification

The submarine pipeline specification developed for Study purposes is extremely preliminary but provides a meaningful basis for evaluation. The brief specification assumed is summarized as follows:

Diameter	:	24" O.D.
Material	:	API 5LX 60
Wall Thickness	:	0.75"
Weight Coat	:	2" to 2-1/2", thickness increased as required for stability or protection
Corrosion Protection		
- external	:	Coal-tar wrapping; thin film epoxy near Hibernia South
	:	Sacrificial anodes
- internal	:	Gas Dehydration
Valves/Fittings	:	ANSI 1500

The landline specification will be similar except for absence of weight coat, and the use of "thin film" powder epoxy coatings for anti-corrosion coating.

No problems are envisaged with pipe design "for installation" due to the relatively small diameter, thick wall pipe. This will be an integral part of the design procedures, however.

The operating pressures upon which the above specification is based are:

Inlet (Hibernia South) : 2,700 psig
Outlet (Long Harbour) : 1,500 to 1,200 psig

The minimum arrival pressure at Long Harbour is assumed to be 1,200 psig with 1,500 psig as the desirable operating pressure just after the line is pigged to remove any liquids and is in the transient "dry" condition. After pigging, the outlet pressure will fall as liquids build up in the line reducing its efficiency. The rate of fall and the final equilibrium outlet pressure will be determined by the rate of liquid production and the profile/elevation of the line. It is not possible to accurately predict the actual operating conditions which may obtain without data on particular gas composition, flow rates and pipeline profile. A series of flash calculations would be used in a rigorous two-phase flow investigation of the pipeline's performance. This is not possible at this level of investigation and so an operating margin of 300 psi is allowed on the arrival pressure of the gas.

7.4 DESIGN AND ENGINEERING

This preliminary investigation can give only an indication of the possible final arrangement and specification of the gas pipeline and its associated equipment.

Basic engineering and detailed design of the pipeline system will require extensive survey and environmental data as well as specific determination of the landed gas specification required. Pipeline design will be an integral part of the total project design interfacing with offshore and onshore process and production facilities and will include both the submarine line and any landline required.

7.4.1 Approach to Design

The following is a brief outline of the approach which would be taken to progress the design and engineering of the pipeline.

As a result of field development planning studies carried out during the pre-project stage, the operator will have a broad outline of the preferred development option including decisions on the design philosophy such as the extent and type of offshore versus onshore processing and preferred pipeline route. A certain amount of preliminary pipeline design will have been carried out and forms the basis for completing preliminary design for the preferred route.

Given a preliminary analysis of gas available for export and the production operating conditions (temperature and pressure from the gas treatment facilities) pipeline gas properties are calculated, i.e., compressibility, viscosity and specific gravity. This is an interactive procedure during design as process/export characteristics are optimized.

For various reasonable optional arrangements of initial compression at the production platform and intermediate boosting, and the required delivery conditions onshore, a sensible range of pipe sizes is selected and the compression requirements for each pipe size estimated. A techno-economic evaluation of the options is then carried out including technical acceptability, operational flexibility and life cycle costs (i.e., a financial evaluation of capital and operating costs over the life of the field, preferably using Discounted Cash Flow techniques in addition to standard accounting criteria). As a result of this evaluation, the preferred option is selected and the nominal pipe size established. This evaluation essentially trades-off increasing pipeline costs as diameter increases with a corresponding reduction in compression costs.

In general, the pipeline will be sized for maximum field production. However, for the submarine line, water depth and installation limitations may constrain the choice of pipe size requiring dual or multiple pipelines to maintain throughput (as for the Trans-Mediterranean pipeline). Such limitations are not expected to apply to the Hibernia development, with the exception, possibly, of twinning the line over critical lengths exposed to significant risk of damage by iceberg scour. For gas lines, provision may be made for the installation of future compression to maintain throughput as field pressure falls.

Concurrent with the above evaluation and providing input to it, a preliminary "desk study" of the preferred route will be made. For the submarine line, hydrographic charts will be used to determine water depth profile and anticipated soils and currents along the route. Published environmental data will also be used. Following evaluation of topographical charts for the landline, a helicopter "fly-over" of preferred routes and landfalls will be undertaken.

The preliminary design of the pipe, including diameter, wall thickness, materials and specific gravity will then be completed for each line section and an assessment made of the various available contractors' ability and their equipment capability to lay the pipeline. This assessment will include cost estimates for materials and construction taking into account the risk levels to which the contractors would be subjected.

A study would also be conducted to determine the lead time required to obtain pipe, coat and wrap, and obtain contractors' commitments.

After the information on timing is complete, all phases of the remaining work would be built into a planning schedule including:

- route and landfall survey (specific)
- data reduction
- detailed pipeline design
- preparation of materials and construction specifications
- obtaining permits
- procurement of materials
- application of coatings and concrete weight coat
- pipeline installation
- survey and inspection
- testing and commissioning
- start-up

Following final approval to proceed, the initial route surveys would commence, followed later by detailed survey of the proposed route. Detailed design of the pipeline will be based on established methods and procedures. Mathematical and analogue models may be used to assist design for installation which represents the most difficult design problems in terms of imposed loads.

7.4.2 Design Guidelines and Regulations

The most comprehensive set of guidelines produced for offshore pipelines is that by Det Norske Veritas (DNV) "Rules for Submarine Pipeline Systems" 1981. These rules are generally accepted for use throughout the North Sea and may be applied to the Hibernia development. The following code of practice is of general application world wide:

> American Petroleum Institute (API) - RP1111 -
> "Recommended Practice for Design, Construction, Operation and Maintenance of Offshore Hydrocarbon Pipelines" 1976

Reference may also be made to the United Kingdom Institute of Petroleum (IP) "Model Code of Safe Practice in the Petroleum Industry Part 6: 1971 + Supplement - Submarine Pipelines".

The American National Standards Institute (ANSI) issues general pipeline standards, e.g., ANSI B31.8 - "Gas Transmission and Distribution Systems", ANSI B31.6 - "Liquid Transport" and the API codes for steel quality and welding practice may be supplemented by American Society for Testing and Materials (ASTM) codes. API RP 14E - "Recommended Practice for Design and Installation of Offshore Production Platform Piping Systems" may also be referenced for associated production platform equipment.

Design guidelines for onshore gas pipelines are well established in Canada and would be adopted, as would any future guidelines concerning submarine pipelines.

All Canadian Federal and Provincial Government Acts of Parliament and Statutory Regulations concerning offshore installations in general and submarine pipelines in particular, would be adhered to.

Further, subject to such regulations, all developments must be approved, monitored and controlled. Finally, a number of International Agreements may require to be observed, e.g., United Nations Law of the Sea.

7.4.3 Design Loads

Critical for the design of a submarine pipeline is the understanding of the imposed loads arising from construction and operations.

During installation the pipe is subject to hydrostatic and hydrodynamic environmental loads. Further, depending on the laying method, tension loads are imposed to maintain pipe curvature within acceptable bending limits. The relative motion of the laybarge and the pipe also imparts loads.

Once installed, the pipeline will continue to be affected by hydrostatic loads and, where not buried, wave and current loads with additional hydrodynamic loads where free spans occur. The pipe will also be affected by movement of the seabed and seismic activity. In operation, the pipe will be internally pressurized. The effects of pipeline creep must also be considered for the inlet end of a hot gas export line particularly where an anchoring device is deployed.

The pipeline will also be subject to risk of impact damage by anchors or fishing gear. Local buckling as a result of bending during installation is an important factor in determining wall thickness for a given pipe diameter. Of critical importance is the propagating buckle, which arises when the exterior hydrostatic pressure over and above the interior pressure is sufficient to cause a local buckle to propagate along the pipe. In rare cases, such a buckle may be caused after installation by impact damage. Despite the possibility that the selected pipe diameter/wall thickness ratio may be such that propagating buckles should not theoretically arise, it is prudent to specify buckle arrestors at frequent intervals along the pipe, say every 500 ft. These are more usually required for large diameter thin walled pipe in deeper waters and may not be necessary for the smaller diameter line and shallower depths of the Grand Banks. The requirement for buckle arrestors, particularly in the deeper waters of the Avalon Channel must be considered during detailed design.

When dimensioning the pipe, all design loads must be taken into account, possibly as constraints in the overall design optimization. In general, the construction procedure imposes the greatest strain and risk of damage on the pipeline. In shallower water depths the pipeline physical characteristics may usually be selected to meet the design throughput without significant departure from the economic optimum, maximum permissible pressure being the principal design constraint. In deeper waters, however, diameter/wall thickness ratios for available material and laying techniques limit the selection of physical characteristics. For deep water sections therefore maximum permissible internal pipe diameter may be a limiting factor in the optimization routine. This will require increased compression requirements together with the possible consideration of different pipe diameters along the pipeline length (but with associated increased pigging difficulties). Offshore, variation in diameter generally only arises between booster platforms, if at all.

7.5 CONSTRUCTION AND INSTALLATION

7.5.1 Line Pipe Materials and Manufacture

Steel used for rigid pipelines is typically specified by API requirements and/or similar standards, e.g., DIN or B.S. which classify steels by chemical composition and strength requirements, e.g., yield point, ultimate strength and ductility. The Standards also specify dimensional tolerances, e.g., diameter, ovality, wall thickness as well as alignment and specific weight.

The most frequently used API classes for submarine lines are API 5LX52 to API 5LX65 which exhibit relatively high strength and no distinct yield point.

For offshore applications it is common for stricter requirements to be specified in terms of material chemical composition and tolerences. In particular, weldability is an important factor whilst meeting strength requirements, etc.

Thermo-mechanically treated low carbon steel micro-alloyed with manganese is used for API 5LX60 to API 5LX70 classes, higher strength classes being quenched and tempered to achieve the necessary toughness while maintaining weldability.

Manufacture of welded pipes is limited by the requirement to maintain through thickness high strength for large wall thickness. Seamless pipes may have larger wall thickness but for smaller diameters than achievable by welded construction.

Line pipe may be categorized as either of seamless or welded construction.

Seamless pipe can be manufactured with greater wall thickness than welded pipes but are limited to smaller diameters, up to say, 26".

Requirements for large diameter line pipe are met by welded construction which may be of either spiral or longitudinal configuration.

Spirally welded pipes, which are widely used onshore, may be manufactured in long lengths limited only by handling and transportation constraints. Pipe diameter is not limited by plate width as in longitudinal construction and the manufacturer's equipment is readily adaptable to varying pipe specifications. Demand for short runs of pipe are most easily met by spiral welding.

Longitudinally welded pipe predominates in the offshore industry having reduced weld length and internal stresses. The size of press available at the manufacturer's plant limits diameter, wall thickness, pipe length and material yield point which may be specified. Joint lengths up to 60 ft. may be available but 40 ft. is most common for offshore use, the longer length being more applicable onshore. Double jointing of two 40 ft. lengths is common, however, following delivery to the pipeyard and given suitable laybarge capability. Alternatively double jointing may be carried out on the laybarge prior to adding the double joint to the pipeline.

In general terms, line pipe is available in diameters up to 64" diameter and 1.25" wall thickness up to API 5LX65. Higher strength materials limit diameter and wall thickness and are available on special order. Canadian mills, however, cannot at present supply the 24" diameter 0.75" API 5LX60 line pipe adopted for Study purposes. Future increased capability are uncertain at this time.

7.5.2 Pipe Supply, Coating and Handling

Pipe coating of the submarine line pipe for anti-corrosion and weight purposes is normally carried out at a pipe yard, the location of which minimizes the length of the supply route to the offshore location. It is likely that a new pipe yard would be established in Newfoundland for the purpose of coating the Hibernia line pipe (as well as for, possibly, fabricating the in-field flowline bundles).

If "thin film" powder epoxy or other "novel" coatings are to be used, these may be applied at the pipe mill. Otherwise, the line pipe will be delivered, by sea to Newfoundland, uncoated.

At the pipe yard the line pipe would be double-jointed, if appropriate, have cathodic protection anodes attached (usually "bracelets" secured around the pipe), anti-corrosion coatings added, and concrete coating applied, most likely using the "impinging" method. The concrete density may be increased by the addition of high density ore, the coating being reinforced by a steel re-bar cage. Depending on detailed evaluation of the pipelaying procedure and likely imposed loads, slots may be elected to be cut in the concrete coating to reduce the bending stiffness of the coated pipe. It is preferable that this be avoided, however.

Following curing of the concrete coat, the pipe will be stockpiled in readiness for transportation to the pipelay barge.

Line pipe for the landline may be supplied in joint lengths up to 60 ft. as required. It may be coated at the pipe mill and will be stockpiled along the pipeline route in readiness for installation.

7.5.3 Installation of the Submarine Pipeline

In essence, installation comprises the following activities:

- route survey (pre-design and pre-installation)
- route preparation by pre-trenching/blasting as required
- transportation of line pipe to the offshore location
- pipeline production
- submerging the pipeline to the seabed
- trenching/burial
- completion of offshore tie-ins and landfall
- testing, post-installation survey, and commissioning

.1 Route Survey

Route surveys are essential to establish data for pipeline design, selecting installation vessels and equipment and formulating the installation programme.

Following a desk study of alternative routes using published hydrographic charts and data, an initial survey of the preferred route is undertaken to determine its acceptability and to confirm that there are no obstructions which would hinder the pipeline. This would be a sidescan, bathymetric and stratigraphic survey which would enable pipeline design to commence and a planned profile of the route to be prepared. Also, the detailed route survey would be planned.

The detailed survey would provide the following information:

i) The exact definition of the beginning and end of the pipeline and establishment of reference datum (e.g., by ATNAV or HI-FIX navigation systems)

ii) Water depth profile and variation along route.

iii) Seabed profile and level relative to a defined water level (e.g., LAT) using high resolution bathymetric survey devices.

iv) The nature of the seabed in terms of its composition and behaviour and the possible variation in trench depth for pipeline cover using coring/sampling devices, side scan sonar, sub-bottom profilers. Cables and metallic objects would be detected by a magnetometer survey.

v) Environmental conditions in terms of frequency and severity of storm, wave heights, current profiles with depth, directionality, etc. Data may be available from existing offshore installations and weather stations possibly interpolated or extrapolated for the specific locations. In critical areas, e.g., shallow waters and coastal regions, a higher density of sampling may be required for the implementation of a specific survey.

A pipeline corridor of approximately 3,300' width would be covered, the survey vessel having sophisticated position fixing and tracking equipment, identical to that which will be used by the pipelay barge, for accurately locating the pipe track with a high degree of repeatability.

At areas of particular interest or importance (e.g., tie-in locations, seabed anomalies, cable crossings) direct inspection by RCV, submersible or divers would be undertaken and a photographic/video record made.

Following reconnaissance and selection of the landfall site, a detailed survey of the landfall, surf zone and in-shore approach would be undertaken.

.2 Route Preparation

Following detailed survey, and prior to pipelaying, the seabed in areas of the route which present difficulties will need to be prepared. This applies particularly to any unavoidable outcroppings of rock which will need to be blasted level and to the in-filling of hollows in rocky areas by means of dumping stone rip-rap to provide a smooth seabed profile. A considerable amount of such activity may be required where the route crosses the rocky Avalon Channel and approaches the landfall. Established methods and techniques are available for the water depths envisaged.

In addition any areas of major seabed sandwaves may need to be "pre-swept" to ensure the pipeline is installed below the trough of such waves. There is some evidence[1] to suggest such seabed mobility in water depths less than 400 ft. on the Grand Banks in the thin, surficial sands overlying the more stable gravels. Detailed survey will be required to determine whether post-lay trenching may adequately cope with such areas as opposed to pre-sweeping.

At the landfall pre-trenching inshore through the surf zone and across the foreshore will be required. In sand, the depth of cover in areas of high current/wave activity will need to be in the order of 6 ft. to 9 ft. below the lowest expected beach or seafloor profile over a period of, say, 50 years. In rock, depth of cover required is reduced to, say, 1 ft. to 2 ft.

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1. Fader, Gordon B. and King, Lewis H., "A Reconnaissance Study Of The Surficial Geology Of The Grand Banks Of Newfoundland; in Current Research, Part A., Geological Survey Of Canada, Paper 81-1A, p. 45-56, 1981.

For the inshore survey, conventional survey vessels may be used for water depths greater than 30 ft. with a smaller vessel or barge in shallower waters.

Inshore pre-trenching in sand/clays would be done with conventional dredgers, sheet piling being used as appropriate to support the trench through the surf zone together with jetties, etc., to support construction equipment.

Trenching in rock will require combined explosive fragmentation and mechanical excavation. Typically, mechanical dredgers can operate in water depths down to 100 ft.

.3 Pipe Transportation

As laying proceeds, coated pipe must be transported from storage to the laybarge by sea. Conventional supply boats may be used but specialist pipe supply vessels are available with much greater deadweight and deck space capability, say, 1,500 to 2,500 ton dwt (compared to the larger supply vessels which are more commonly less than 1,500 ton dwt).

The larger laybarges, particularly the third generation semi-submersible types, have considerable on-board storage capacity (up to 7,000 tons depending on the barge) which acts as a "buffer" during weather conditions when pipelaying is still possible, but supply operations are suspended.

For the Hibernia application, given the length of line and the severe environmental conditions which may be encountered, pipe supply vessels ("pipe haulers") are to be preferred, say, six such vessels possibly being required.

.4 Pipeline Production/Submerging

Several methods are available for laying pipe offshore, i.e.:

- * Pipelay Barge - using a "stinger" and an 'S' curve pipe submergence configuration and where significant welding is carried out offshore (50% with supply of coated double joints, 100% with single joint capability only).
- * Reel Barge - whereby pipe with diameters up to 16" are welded and reeled onshore to be unreeled/submerged offshore without a "stinger" and in a 'J' curve configuration.
- * Flotation Method - whereby long lengths of pipe are welded onshore and either surface or sub-surface towed to the location for laying either by passing over a conventional laybarge or by separate submergence and underwater connection.
- * Bottom/Off-Bottom Tow - whereby long lengths of pipe are welded onshore and either towed along the seabed or at a fixed height above the seabed using combined buoyancy/chain height control separate lengths being connected underwater.

Bottom/Off-Bottom Tow has been demonstrated offshore for moderate lengths of large diameter pipe but the line length applicable for Hibernia is considered excessive for the application of this method, which is reasonably susceptible to risk of pipe loss and/or damage, particularly over the rocky zones of the Avalon Channel.

The Flotation Method is not yet sufficiently proven, there being a high risk of damage during tow, and particularly where laying takes place over a conventional barge due to the relative motion of the floating pipe and the barge during rough weather.

The Reel Barge Method cannot handle the 24" pipe diameter required (but would otherwise be fast and acceptable and may be used for some in-field times).

Conventional pipelaying is therefore the preferred approach for the Hibernia pipeline. Choice of vessel will depend on detailed study, including possible operational simulation, and economic analysis. It is anticipated that, given the long length of line and the severe environmental conditions, such an analysis would demonstrate that the greater laying capability of a third generation semi-submersible laybarge, albeit at a greater contract day-rate cost, would provide the most economic laying configuration, compared to large ship-shape barges. Box-shaped barges are not considered desirable in the environment anticipated.

When operating normally, such a semi-submersible barge should be capable of laying at least 2 miles/day. Downtime for weather, mechanical breakdown and non-productive operations should be better than 30% of overall time within a weather window for laying of, say, 180 days at the Hibernia location, May to October. Conservatively, 40% downtime has been included in the cost assessment. It is considered possible that, given the particular characteristics of the Hibernia location, which include the risk of heavy ice early and late in the season, fog during mid-year, pack-ice, etc., the laying season may be shorter, say, five months, May to September, and the effective downtime may approach 40%.

The risk of icing is a particular hazard for the pipe supply vessels and the anchor-handling tugs of the laybarge. The laybarge operational sea state is likely to be limited by the ability of the tugs to handle anchors rather than the barge to lay pipe, say, sea state 4 to 5 as opposed to 6.

To lay the whole pipeline, a single third-generation semi-submersible laybarge would be required for two seasons.

.5 Trenching/Burial

The necessity for trenching as well as weight coating the pipe, and possible disadvantages of conventional pipeline trenching, have been discussed in Sub-Section .3 above.

It is important to distinguish between trenching and burial. Trenching refers to the opening of a trench with the purpose of lowering the laid pipe below the surface of the seabed with the subsequent possibility that the pipe may be covered in part by natural backfill. Such backfill is unlikely to provide significnt cover in deeper waters but is usually reasonably successful in shallower waters subject to wave and current action. Burial refers to the deliberate re-covering of the pipe by mechanical or other means, e.g., sandbags, mats and rip-rap, etc.

Burial is rarely undertaken for main gas pipelines over the major part of their length unless required by government regulations. Burial is necessary for pipe stability at the landfall and shore approach. In areas of sand, etc., however, natural backfill is normally adequate. In rock trenches, mechanical backfill, probably using aggregate will be necessary. Apart from the FLAGS pipeline in the North Sea, however, most major submarine pipelines have been trenched in suitable soils.

In relatively shallow waters, say less than 100 ft., conventional suction or mechanical pre-trenching may be used. In deeper waters, it is conventional to post-trench the line, if required, by means of:

- Jetting;

- Fluidization; or
- Mechanical Cutting.

Jetting is the most common method, depending on soil conditions. Pre-trenching using ploughs may also be considered. It may be noted that, historically, more damage to pipelines has been caused by trenching than any other cause.

The surficial soils overlying the semi-consolidated Cretaceous-Tertiary "bedrock" on the Grand Banks are generally a gravel lag overlain in places by a thin sand layer. The sand and gravel layer thickness is variable and generally not great. Conventional depths of trenching, e.g., 3 ft. to 6 ft. minimum cover over the pipe below surrounding seabed should be achievable using jetting in the sand and gravel layers, with some undefined penetration into the "bedrock". Multiple passes of the jet sled are likely to be required in all but the most ideal soil conditions, and additional passes will be required should survey indicate the unacceptable pipe spanning between high points.

Due to the environmental conditions at Hibernia, a small, semi-submersible laybarge has been assumed used as a trenching barge for Study purposes using a jet sled for trenching. Sled pressure ratings up to 2,500 psi are available, high pressures being used in relatively hard soils with lower pressures for sand.

Historically, due to mechanical difficulties and the necessity for multiple passes, overall trenching rates are low, and will be less than the pipelaying rate. A trenching rate of 1.5 miles/day has been assumed for cost assessment purposes together with an overall efficiency of 50% during a 180-day trenching season. The trench barge would thus be required for two seasons following behind the laybarge.

For Study purposes it has been assumed that trenching to conventional depths of cover can be achieved over 200 miles of the 260 mile route, trenching not being possible in rock areas such as the Avalon Channel.

Studies carried out by others have suggested that the use of pipelines to shore from Hibernia may require a depth of cover of at least 25 ft. to achieve a high degree of protection from iceberg scour damage. The corresponding depth of trenching, e.g., 30 ft., is not possible with currently available equipment. Trenching for avoidance of iceberg damage was therefore excluded from the scope of this preliminary investigation. Similarly, trenching through rock areas, other than conventionally at the landfall, is excluded.

Associated with the trenching spread should be a survey spread to detect rock outcrops, etc., in advance, to prevent damage to the trench sled. Boulders, etc., within the surficial soils, the occurrence of which is not known, will also damage equipment and hinder progress.

.6 Tie-ins and Landfall

Tie-in to the Hibernia South riser base will be by pull-in sled. A tie-in spread is required to attach the pull-in sled, attach buoyancy to the pipeline if necessary and achieve the tie-in.

For Study purposes, it has been assumed that a semi-submersible drilling rig will be available in the Field for general subsea construction work, including tie-ins.

At the landfall a conventional pull-in of the pipeline is assumed, the laybarge anchoring offshore and producing pipe which is pulled along the pre-trenched route by a cable from onshore. The laybarge will then proceed to lay away from shore.

Depending on the procedures adopted for pull-in at the Hibernia South riser base, there may be a preference to lay away from the riser base also. In this case, a mid-point tie-in would be required. Alternatively, a spool piece may be used at the offshore end.

.7 Post-Lay Survey, Testing and Commissioning

Following completion of laying and trenching, and prior to flooding and testing of the line, a post lay survey must be undertaken to determine the as-laid condition of the line and to establish the requirement for any remedial work, such as further trenching of unacceptable free spans or stabilization of the line by grout bagging or rock dumping, etc. Any necessary remedial work must be carried out and the line resurveyed. Such survey will include bathymetry, side scan sonar and underwater video inspection.

Following validation and acceptance of the as-laid condition, the line will be flooded and hydrotested for leaks. It is assumed that final acceptance testing may be carried out in the absence of the production platform, with pressurization being provided from the landfall end. The standard industry practice is to test at 90% of the specified minimum yield strength of the pipe.

Any leaks discovered during the test must be repaired and the test repeated until line integrity is assured. Should a significant period arise between final hydrotest and commissioning of the line, the line will be filled with water containing a corrosion inhibitor, procedures for subsequent disposal of which must be specified.

When all system components are in place, including the landline, gas reception facilities and Hibernia South production platform, a final hydrotest may be performed. The line would then be dewatered by means of pigs propelled by compressed air. This would be followed by cleaning using a combination of several pig types (displacement, foam wire brush and finally foam-poly pigs) propelled by compressed air to remove any water residue, rust, deposits, etc. After cleaning, a gauging pig would be run to detect any pipe deformation and, if necessary, remedial work carried out. Final dehydration by means of either methanol swabbing or vacuum would be carried out. The final stage of commissioning is to fill the pipe with gas by means of passing several slugs of nitrogen between a number of pigs propelled by the pressurized gas to displace the air. The transmission line would then be ready for production.

7.5.4 Installation of the Landline

Installation of the landline from Trepassey Bay to Long Harbour would follow established onshore pipelining practice in Canada and is not detailed here.

In the absence of detailed route survey data, it is assumed that substantial rock grading and trenching will be required onshore together with a relatively higher number of creek/river crossings. The extent of such difficult terrain will add significantly to the cost of the landline.

It is assumed that all route preparation will take place in one season with pipelaying and backfill being carried out the next. Alternative methods of pipe protection in rock areas, e.g., berming without ditching, may be considered in basic engineering to reduce costs.

7.6 OPERATIONS, MAINTENANCE AND REPAIR

7.6.1 General

The operations and maintenance requirements of a submarine gas line and landline are not complex.

Operation of the line on a day-to-day production basis reduces to monitoring and analyzing the flow of gas through the system and running displacement pigs/spheres as required to remove liquids which may drop-out in the line.

For the submarine gas line, a programme of regular survey and inspection will be required to maintain the integrity of the pressure envelope. This integrity is important not only from safety and pollution aspects but also when considering the high costs of repair plus potential loss of revenue. The programme of survey and inspection will therefore be devised to meet desired safety standards and continuity of production, but at the lowest cost.

Inspection will be the principal tool employed by the operator in predicting the physical requirements for maintenance and repair of offshore pipelines.

As with all inspection programmes, the as-laid condition report must be maintained from all phases of the construction of the line as well as a record of the design information. Only then can subsequent in-service inspection concentrate on potentially significant areas.

In addition to the possible checking of pre-determined sections of the line, a general survey is normally needed at regular intervals, normally annually.

Changes in condition of the pipeline which may cause concern, together with the implication for production operations, are as follows:

Change in Pipeline Condition		Implications[1]
1.	Exposure of pipe which was previously covered	A,B
2.	Loss of concrete coating (reinforcement may or may not be removed)	A,B
3.	Movement of pipe on bottom	A,B
4.	Loss of anti-corrosion coating	A,B
5.	Pitting of steel surface or loss of wall thickness	A,B
6.	Depletion or loss of sacrificial anode protection	A,B
7.	Spanning of pipe	A,B
8.	Dented or buckled pipe (but will pass a pig)	A,B
9.	Debris on pipe	A,B
10.	Progressive loss of concrete	B
11.	Flotation of pipeline section	B
12.	Pipe wall gouged/cracked	B
13.	Pipe dented or buckled badly, will not pass a pig	B,C
14.	Pinhole leak or leaking crack	C
15.	Pipe ruptured	C

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[1]

A Minor change in condition that does not affect normal operation and does not need maintenance and repair.

B Change in con[illegible]ion which may influence the operation if not monitored an[illegible]fied before it becomes excessive.

C Major change [illegible]ition interrupting pipeline operation.

7.6.2 Survey and Inspection During Operation

Each year, a survey of the submarine pipeline will take place in order to determine the current condition of the pipeline. Survey equipment used is similar to that required for the as-laid survey, i.e.:

- bathymetry
- side-scan sonar
- sub-bottom profiler
- RCV/submersible

For buried pipe, the general survey is first of all aiming at detecting uncovered pipe and free spans and large debris on the route. For non-buried pipe the general survey may include video records or direct inspection by manned submersible or on-bottom vehicles. Questionable sections discovered during the general survey are subjected to close inspection, for example by divers, using the required mapping and non-destructive testing (NDT) techniques.

Any change in the condition of the pipeline or the surrounding seabed would be noted and the records updated to keep track of the history of the pipeline.

Normal submarine pipeline inspection practice is a continuous video survey of all exposed sections; usually, manned submersibles are employed but remote controlled free swimming or bottom located vehicles can be used. The video may be supplemented by close-up still photography of suspected damage and by diver inspection of any suspended spans.

Major leakage is readily detected by loss of pressure or visual inspection. Minor leaks are more difficult to detect but may also be found visually or acoustically using leak detection sonar equipment. Alternatively, a diver-held or towed Hydrocarbon Profiler ("Sniffer") may be used to detect the presence of hydrocarbons in the water.

Survey of the landline will be conventional.

External inspection of the submarine pipeline as regards corrosion is difficult due to possible burial and the presence of the concrete weight coat. With the use of cathodic protection, however, the rate of corrosion will be greatly reduced and inspection reduces to monitoring the condition of the cathodic protection, supplemented by wall thickness measurement of line sections where damage to the concrete weight coat exposes the steel.

Whereas direct measurement of external pipeline corrosion may be difficult, measurement of the effectiveness of the applied cathodic protection system throughout the length of the offshore pipeline is relatively easy and fairly reliable.

The conventional cathodic protection monitoring method relies upon measurement of pipeline-to-environment electrical potential which can be measured using a reference electrode close to the pipeline and a corrosion voltmeter in contact with the steel pipe by means of a cable through the concrete coating. The potential readings obtained, when properly interpreted, can indicate areas of under-protection in terms of failure of the cathodic protection system or may indicate areas of probable high corrosion rate.

Systems recently introduced obviate the need for an electrical contact through the concrete coat by measuring the field strength around the pipe, although contact is desirable for calibration purposes. Current entering or leaving the pipeline at the anodes or any defect can also be measured.

Internal inspection by intelligent pigs may be made, given suitable arrangements and can detect local distortion, thinning of the pipe wall and general defects greater than 15% of wall penetration. The use of intelligent pigs is not essential, however, as long as alternative corrosion monitoring procedures are acceptable, e.g., electrochemical or electrical resistance probes, weight loss coupons, etc.

It should be noted that special surveys or inspections may be required in addition to the regular surveys as a result of abnormal circumstances or regulatory requirements. In addition, complete survey of relevant areas will be required following any remedial work carried out.

The corrosion and condition of cathodic protection monitoring procedures for the landline are similar but simplified due to the "dry land" environment.

7.6.3 Pipeline Maintenance

Maintenance of offshore pipelines will normally be attempted as a result of inspection and in instances where lack of maintenance would almost certainly lead to a reduction in the pipeline operating life and/or disruption of production.

There are few truly maintenance functions associated with offshore pipelines. Replacement of consumed cathodic protection anodes, covering sections of pipeline appearing above the mudline or giving support to sections of pipeline suspended above the mudline as a result of scouring are the principal maintenance activities. Suspended or exposed pipe would normally be supported and/or covered with grout bags, sandbagging or stone dumping.

When the pipe is required to be covered, either for on-bottom stability or protection purposes, but where trenching is not possible or has been unsuccessful, shaped concrete sections can be installed. Such devices may also be used to protect damage sensitive installations such as "Tee-Pieces". Alternatively, having backfilled any scour depressions and provided support for free spans, erosion control mats may be laid over the exposed pipe and covered with stone rip-rap. A great deal of research has also been carried out in Norway on laying a continuous series of flexible concrete slabs or a continuous concrete "carpet" over the untrenched pipe.

Maintenance requirements of the landline are less than for the submarine line and will relate mainly to the submerged integrity of the pipeline at river crossings and through marshy areas.

7.6.4 Submarine Pipeline Repair

The water depths in which the Hibernia pipelines would be laid are within the limits of conventional offshore pipeline repair techniques and should present no particular difficulties unless attempted in severe sea conditions.

Maintenance and repair is currently effected by divers using the techniques of welding, flanging or mechanical connection assisted by subsea vehicles, manipulation devices alignment frames and/or habitats as required.

In preparation for repair, a thorough inspection must be carried out to determine the extent of the damage, whether it should be repaired, and possibly how the repair can be done. If the damaged part of the pipeline is buried, the pipeline has to be "dug out". Typically, pipe cover may be approximately 3 ft. in deeper waters, 10 ft. near shore, but depending upon the possible oblique angle between the pipe ends after cutting, the uncovering of a substantial length (in excess of 65 ft.) may be necessary. On the other hand, attachment of a collar coupling may require the uncovering of less than 10 ft. only. The principal method of uncovering is high pressure water jetting and/or mass removal of spoil by suction. The methods are suited to unconsolidated materials and there is little experience of uncovering pipelines in cohesive materials.

All residue of gas must be removed from the pipe if a damaged pipeline is to be cut for repair. This is necessary for safety reasons and is normally done by sending a slug of water down the line between displacement pigs. Where the line is flooded, this may be accomplished from the repair site.

The pipe protection has to be removed over a certain length of pipe, depending on the extent of damage and the repair method. Possible methods for removing the concrete weight coating and pipeline protective coatings are:

- water jetting (c.a. 14,500 psi)

- hydraulic sawing
- use of explosives

Three main methods of pipe-cutting are employed underwater as follows:

- The oxygen arc method has so far been the most-used method for rough cutting of steel constructions. The steel is melted by means of an electric arc and is then cut by means of a high pressure oxygen jet.
- Mechanical cutting by means of a hydraulically operated rotating cutter is a very simple operation for a diver to carry out and is also well-suited for remote control operations.
- Explosives may be used in the form of a ring charge placed around the diameter of the pipe. Explosives with surplus oxygen may present a danger if there are remnants of gas in the pipeline.

Once the pipe has been uncovered and the extent of the damage assessed several alternative repair methods may be adopted.

The failed section of the pipeline will either be replaced or repaired by a full encirclement sleeve. Patching is not suitable for a high pressure pipeline.

Whether replaced or encircled, a further choice must be made between the use of underwater welding systems or mechanical connectors. Given the relatively shallow water depths, and the high pressure of the line, welded connection is likely to be preferred although most principal types of proprietary mechanical connectors are designed to handle the line diameters and pressures being considered here. Flanged connectors are not considered appropriate for this application.

The final choice is whether to repair underwater or to bring the line to the surface for repair. In the water depths considered here, it will not be possible to bring the line to the surface for small repairs without cutting the pipe. Where the pipe has been cut, flotation methods combined with lifting would be used for bringing the pipeline to the surface under tension, the pipe ends having been dewatered. Repairs carried out with laybarge assistance are, however, expensive, weather dependent, time consuming and furthermore, entail the risk of further damage to the pipe.

There are several techniques for welding underwater. These are:

- wet welding
- dry hyperbaric welding either in a chamber or with a dry welding zone
- dry atmospheric welding
- explosive welding

The crux of any welded underwater repair is the ability to obtain sound welds on the high strength steels used on offshore pipelines and to meet the specifications of the Certifying Authority.

Dry hyperbaric welding is the conventionally used method and the water depths along the Hibernia route are within the limits of diver application; costly, remote-controlled repair modules or dry, one atmosphere chambers will therefore not be required although alignment frames for 24" pipe will be reasonably large and heavy.

Local damage may require replacement of only tens of feet of pipe but extensive iceberg scour and dragging may require replacement of hundreds of feet.

Depending on the repair methods and equipment used, its mobilization time, time of year and the weather conditions, a repair may take from several weeks to several months.

For short lengths of damaged, removed pipe, a spool piece may be fabricated onshore or on a work barge. For longer lengths, a new section of pipe may need to be laid either by laybarge or, more likely by off-bottom tow.

7.6.5 Landline Repair

Repair of the landline will follow conventional onshore practice both for buried sections and for pipe installed at river crossings or through marshy areas.

7.7 ASSOCIATED FPF SYSTEMS AND EQUIPMENT REQUIREMENTS

7.7.1 Gas Transmission System Requirements

An integrated approach has been taken with respect to establishing the topsides facilities conceptual requirements and arrangement for Study purposes in terms of maximum utilization of production equipment, systems and utilities.

Given the Hibernia Field development concept, as adopted, few additional systems or equipment requirements arise as the result of integrating gas export with the oil/gas production and gas injection systems.

Accepting the gas transmission philosophy that a condensing gas may be exported, the only gas conditioning equipment required is a dehydration package (which is not required for gas re-injection). To reduce the system specification, it is envisaged that the dehydration would be carried out prior to the main sales gas compression. Detailed design may indicate advantages of post-compression dehydration however. The unit would be switched out of service when only gas re-injection is required.

The sales gas off-take point in the gas re-injection compressor train would be following the interstage cooler and knock-out vessel after the first stage of the two stage centrifugal injection compressor train. No significant additional compression system requirements arise if this arrangement is acceptable.

The only other topside equipment and systems requirements which can be directly associated with sales gas export are:

i) Metering for sales and fiscal purposes

ii) Pig/Sphere Launching
iii) Instrumentation and Control Systems
iv) Telecommunications Link to Shore

Utility consumption (water, power, inert gas, etc.) will increase due to the inclusion of the gas dehydration unit but not significantly. Additional piping, instrumentation and bulks will be required but these will be small, contingency items.

Additional lines will be required in the riser system plus an additional pull-in module in the Riser Manifold Base with associated pipework and control valves, etc. Should it not prove possible to launch pigs/spheres directly into the main gas line from the FPP deck, then a subsea pig/sphere injection unit will be required.

The principal additional equipment and system items required are discussed below.

7.7.2 Gas Dehydration Package

For water dewpoint control for 250 MMSCFD, two glycol dehydration units can be envisaged (125 MMSCFD each) with the necessary regeneration facilities.

The following equipment will be involved:

- * Glycol Regeneration Package, including:
  - glycol stripping column
  - glycol regenerator column
  - glycol regenerator

  - glycol/glycol exchanger
  - glycol filters
  - glycol charcoal filter
  - glycol flash vessel
  - pH control chemical tank and injection pump
  - glycol recirculation pumps
- Glycol Contactor, including:
  - produced gas heater
  - gas/glycol exchanger
  - produced gas exchanger
- Glycol Storage Tank/Sump/Pumps

Typically, both Glycol Regeneration Packages may require a combined deck space 30 ft. x 75 ft. on the upper deck with the Glycol Contactors/Exchangers mounted vertically outside the enclosed area. The Glycol Storage Tank/Sump/Pumps would occupy a small area on the lower deck.

The combined dry and operating weights for the two units would be in the order of 220 tons and 260 tons respectively.

A gas analyzer would be located on the gas line leaving the platform to monitor the quantity of water remaining in the gas.

7.7.3 Gas Metering Skid

The gas metering skid, required for sales and royalty purposes, would occupy an area of approximately 45 ft. x 18 ft. x 15 ft. and weigh approximately 80 tons.

7.7.4 Pig Launching Facilities

It is considered likely that the full 24" main gas line diameter will not extend up the Hibernia South FPP Riser; either multiple lines will be used or at least a single line of lesser diameter. Given such an arrangement, it will not be possible to inject pigs/spheres into the line directly from the FPP deck. Pigging/sphering will be required both to displace any liquids accumulating in the submarine section of the pipeline, and, from time to time, for cleaning scale, hydrates or other deposits from the line. Pigs/spheres will also need to be run during commissioning, start-up and possibly in the event of line rupture but in this case bi-directional pigs may be utilized.

It is likely that a subsea pig/sphere injection package will be required. Pigs/spheres would be loaded into a cartridge on the FPP deck, the cartridge being run down to the Riser Manifold Base on guide lines. A diverless latching interface with the Riser Base is preferrable for all connections. Similar systems would be adopted as will be used to connect the riser bottom assembly to the Riser Base. The system would contain all necessary door interlocks, pig counter/ detection facilities similar to a deck mounted system.

Arrangement of such a system to permit "intelligent" pigs to be run (for internal inspection/monitoring purposes) is likely to be more difficult due to their increased length compared to, say, displacement or cleaning pigs. Under current guidelines and regulations, however, the use of intelligent pigs is not mandatory as long as other inspection procedures are used which satisfy requirements.

It is understood that General Descaling have developed such a system for the warm, shallow waters of the Gulf of Mexico but its direct application to Hibernia is unlikely. The system would therefore need to be entirely new equipment item, specifically designed and developed for Hibernia in conjunction with the Riser and the Riser Base.

7.7.5 Gas Conditioning

The separator off-gas is conditioned for hydrocarbon dewpoint control by pressure/temperature alone.

Should a higher quality gas specification be required, not the case adopted here, then more complex gas conditioning equipment will be required, in addition to the equipment outlined above.

Four main types of hydrocarbon dewpoint control processes are available:

- Refrigeration
- Expansion/Recompression
- Adsorption
- Absorption

Typically, a refrigeration package may be used, the gas/gas exchanger and the chiller unit lengths being in the order of 40 ft. and 20 ft. respectively, the whole package weight dry/operating being in the order of 250/300 ton.

The necessity to produce a higher quality gas will require additional space and load capacity on the FPP.

7.8 SYSTEM FLEXIBILITY WITH RESPECT TO ADDITIONAL GAS QUANTITIES

7.8.1 Introduction

As discussed in Section 7.3.3, the selected 24" pipeline has the capability to transmit 430 MMSCFD of "dense phase" gas, accepting an inlet pressure of 2,700 psig (310 MMSCFD at 2,200 psig). These throughputs allow sufficient margin for pressure drop - due to liquid drop-out in the line - and represents a margin of 72% (24%) over the average throughput of 250 MMSCFD.

The 24" line therefore has sufficient flexibility to handle peak loads from Hibernia, given the production premises adopted. Margins are not, however, considered sufficient to accept incoming gas from elsewhere, at peak Hibernia rates, without the deferment of Hibernia gas production. The acceptability of deferment will depend on its duration and quantity.

As production from Hibernia declines, however, spare capacity will become available. Utilization of such spare capacity will depend on development phasing between Hibernia and other adjacent prospects.

7.8.2 Increased Line Sizes

Quantities of additional gas which may become available from outside the Hibernia Field cannot be defined at this time. For general information therefore, indicative line sizes have been estimated for up to approximately four times the Hibernia average rate, assuming an identical pipeline routing and inlet/outlet pressures of 2,700/

1,500 psig as for the 24" line. Lines sizes estimated for "dense phase" transmission are as follows:

Line Size	Peak Throughput (MMSCFD)
28"	650 (2.60)
30"	780 (3.12)
32"	930 (3.72)

Data in parenthesis are the multipliers of peak throughput on the average Hibernia throughput of 250 MMSCFD.

Permitting the outlet pressure to reduce to 1,200 psig assuming the transmittal of "dry" gas, would increase throughputs by approximately 10%. A further reduction to 500 psig would permit an ultimate capacity a further 10% higher.

It is therefore noted that line size is relatively insensitive to throughput, significant spare capacity being achieved through relatively small increase in diameter. The associated increase in cost will relate principally to line pipe material and longer laying times.

7.8.3 Associated Facilities

With regard to handling additional quantities of gas from outside Hibernia, three alternative options can be envisaged:

i) The remote source provides gas of suitable quality and sufficient pressure to "tee" into the main gas line downstream of the Hibernia South compression facilities.

ii) The remote source provides gas of suitable quality and pressure to commingle with the Hibernia gas at the suction of the Hibernia South gas compression system.

iii) Gas arriving at Hibernia South requires both conditioning and compression prior to transmission.

Since no gas conditioning equipment other than dehydration is provided on Hibernia South, additional gas must be considered conditioned to suitable quality at the remote source. Unless Hibernia and other prospects are combined into an integrated development by common partners to their mutual benefit it is not considered reasonable to install conditioning equipment and/or to provide space and deck load capability for future utilization by others. Option (iii) is therefore not considered reasonable.

With regard to Option (ii), small quantities of additional gas, say, up to 10%, may be handle by means of the design margin on the Hibernia South dehydration, compression and metering equipment. However, meaningful quantities of additional gas, say 100 MMSCFD or 250 MMSCFD, could not be handled without significant additional equipment on Hibernia South. For such quantities, the size of the Hibernia South FPP would increase considerably and would demand a complete review of the conceptual Hibernia development plan adopted for Study purposes.

It is likely that a fifth FPP would be required, possibly handling gas treatment and compression only. This would add significantly to the cost of the Hibernia development. However, should production rates at Hibernia be higher than assumed for the purposes of this preliminary investigation, then a fifth platform may be utilized in any event.

It is not considered feasible therefore to accommodate either Option (ii) or (iii) within the conceptual development plan adopted here. The inclusion of a fixed platform in the development plan would however permit consideration of such options.

Option (i) may provide a viable means of permitting the transmission of additional quantities of gas. The operator of Hibernia would specify the gas quality and pressure requirements to the remote producers. Marginal benefit may be gained by requiring a higher quality, i.e., drier, gas than produced at Hibernia.

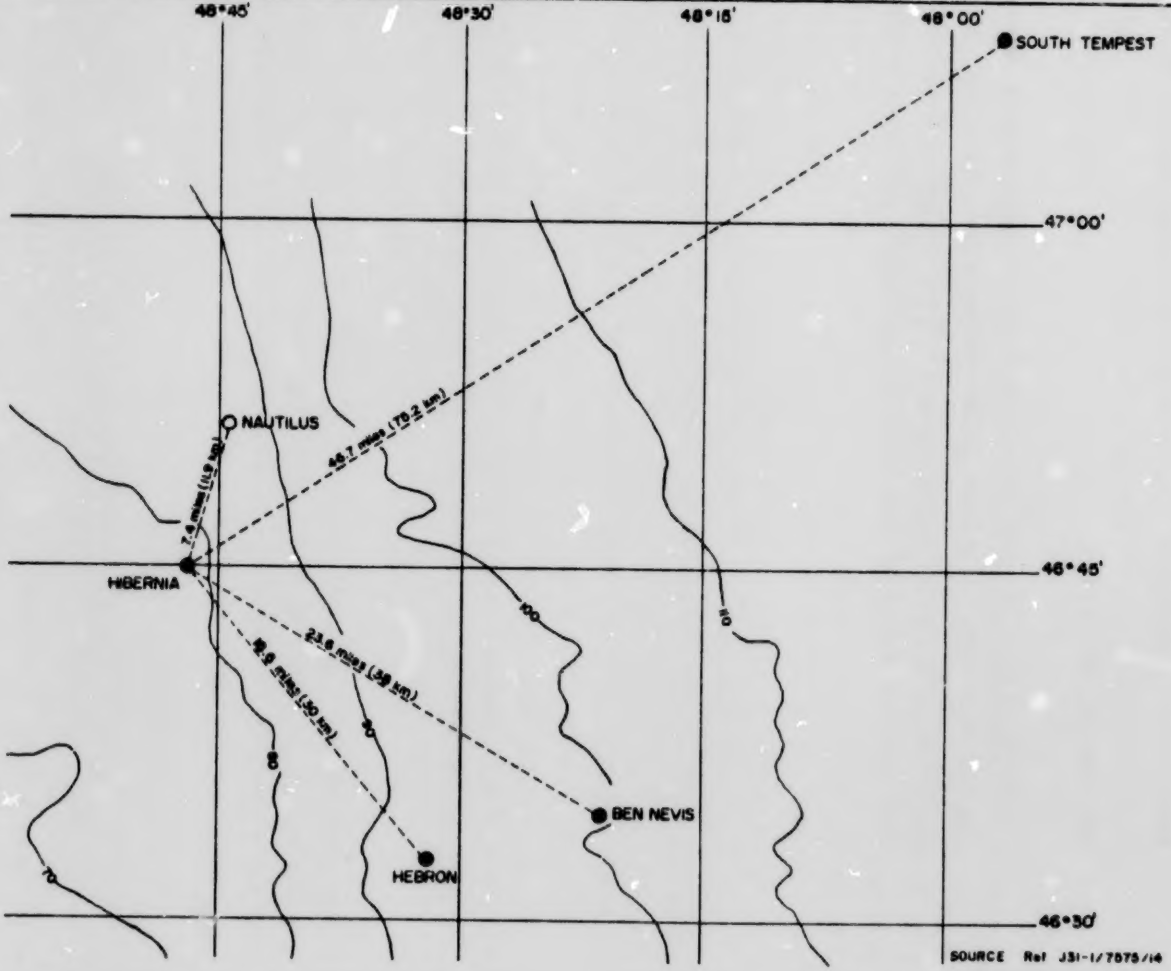
Depending on distance, the remote producers may have difficulty in achieving a suitable commingling pressure, say 2,500 to 2,700 psig, at the Hibernia South Riser Base or "T" piece. With the exception of South Tempest, however, other prospects known to date lie within 25 miles of Hibernia which should permit the delivery of suitable gas with reasonable line sizes (refer to Figure 7-4).

Depending on the quantity of gas envisaged, the concept of a completely separate gas gathering system may be envisaged collecting gas not only from Hibernia but from other sources as well. The organization, financing and implementation of such a system would be a formidable task (vide the lack of success in establishing a UK North Sea Gas Gathering System.

Similar difficulties, though of lesser magnitude will also arise for any additional facilities installed at Hibernia for potential future use by others, including the oversizing of the main gas pipeline.

A situation where future spare capacity in a pipeline installed for Hibernia alone is utilized is more readily envisaged. This will be complicated by the possible initial re-injection of Hibernia gas for

DISCOVERIES IN THE IMMEDIATE VICINITY OF THE HIBERNIA FIELD


48°45'
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47°00'
46°45'
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SOUTH TEMPEST
NAUTILUS
HIBERNIA
BEN NEVIS
HEBRON
7.4 miles (11.9 km)
46.7 miles (70.2 km)
23.6 miles (38 km)
18.6 miles (30 km)
110
100
90
80
70

SOURCE Ref J31-1/7575/14

WATER DEPTH CONTOURS IN METERS

Figure 7-4

some, as yet undefined, period prior to production of the gas, and lack of definition of the depletion profile for Hibernia gas which may thereafter obtain.

Assuming Option (i) may arise, it is considered more reasonable to include a subsea "T" piece in the main gas pipeline than to require modifications to the Hibernia South Riser Manifold Base. No modification would be required to the riser systems in either case.

7.9 DIRECT PIPELINE ROUTE VIA BY BULLS

7.9.1 Introduction

The main emphasis of the Study has been the consideration of a southern submarine pipeline route from Hibernia to Trepassey Bay and thence to Long Harbour. The advantage of this route, compared to a more direct northern route, lies only in its potential for pipeline burial by conventional means. Since a more northerly route would be considerably shorter, significant savings in materials and construction costs may be realised. The length of potentially untrenchable, exposed pipe would be increased with the northerly route and a marginal increase in water depths may be encountered.

The risk of damage to the submarine pipeline from fishing, where applicable, and general marine operations would increase for the northern route due to the increase in exposed pipe length. The relative risk of damage due to iceberg scour between the two routes, which is discussed in Section 7.1, cannot be quantified at this time.

It is therefore appropriate to consider the requirements for, and costs of, a shorter, more northerly route in order to establish a comparative base for route selection. Subsequent to completion of the main Study, such a route via a Bay Bulls landfall has been briefly considered.

7.9.2 Routing, System Configuration and Specification

The northern route requires a 195 mile submarine line. A reasonable landline route from Bay Bulls to Long Harbour is approximately 55 miles long.

For the submarine line, conventional trenching would appear feasible for the 1/3 of the route (approximately 65 miles) which passes over the Grand Banks. The lack of surficial sediments over the hard bedrock in the Avalon Channel (approximately 65 miles) precludes significant trenching of the line by conventional means. The remaining 1/3 of the route, particuarly through the Downing Basin, comprises glacial/marine sediments which will present a difficult, if not impossible, task for conventional trenching, with a high risk of equipment damage if the occurrence of boulders is significant. For Study purposes it is assumed that approximately 50% of the route may be trenchable by conventional means.

Steeper seabed slopes will arise on the northern route, compared to the southern route, and the landfall may present increased difficulties due to the rocky coastline.

A similar system configuration has been adopted for the northern route as for the southern route, i.e., the line has been sized as a continuous length from Hibernia to Long Harbour (250 miles) subject to the provisos relating to alternative arrangements discussed in Section 7.2, e.g., intermediate compression or pressure regulation at Bay Bulls.

The elements of the northern gas transmission system are therefore as described in Section 7.3 for the southern route with the exception that a Bay Bulls landfall replaces the Trepassey Bay landfall (refer Figure 7.3).

The performance of the 250 mile northern pipeline has been assessed on the same basis as for the 330 mile southern line described in Section 7.3.3.

Operating at between 2,700 psig and 1,500 psig, a 20" O.D. pipeline, 250 miles long would have the capacity to transmit 305 MMSCFD of "dense phase" gas. This gives approximately 20% spare capacity over the annual average daily production rate which is considered marginal, at this time, with respect to the throughput peaks which may arise in practice.

Under similar operating conditions, a 22" line would transmit 395 MMSCFD but this is not a standard diameter and may require a premium for supply of line pipe, valves and fittings. In practice, for the length of line considered here, and given sufficient procurement lead time, such premiums may be small, subject to contractual negotiations. The 22" line is not only one size smaller than the next largest standard diameter, 24", but also requires reduced wall thickness for the 2,700 psig operating pressure, i.e., 0.687" compared to 0.75" for the 24" pipe. This introduces a significant saving in material costs although laying costs for the 22" will be only marginally less than for the 24" (the 22" being laid possibly 5% faster). The 24" offers the advantage of additional capacity and, if supply differentials between the 22" and 24" are small, the larger line size would be adopted.

Detailed investigation during basic engineering may result in the adoption of a 22" line, or possibly even a 20" if field production performance analyses confidently predict peak throughputs within, say, 300 MMSCFD. At this time, however, it is considered prudent to recommend a 24" line size (an indication of cost savings for the 22" being provided in Section 9).

NORTHERN ROUTE - 250 MILES

	Inlet Pressure, psig	
Outlet Pressure, psig	2,700	2,200
1,500	500 MMSCFD	360 MMSCFD
1,200	540 MMSCFD	410 MMSCFD
500	590 MMSCFD	477 MMSCFD

Assuming the use of API 5LX60 material, the 24" O.D. pipe will require a 0.75" wall thickness to operate at 2,700 psig. The corresponding wall thicknesses for the 22" and 20" sizes are 0.687" and 0.625" respectively.

In overall terms therefore, the line pipe specification adopted for the northern route is similar to that adopted for the southern route. The requirements for concrete coating and corrosion protection will be similar to those described for the southern pipeline in Section 7.3.3. Further, all comments made in Section 7 concerning Design and Engineering; Construction and Installation; Operations, Maintenance and Repair; Associated FPF Systems and Equipment Requirements apply equally here.

7.9.3 System Flexibility

The adopted 24" pipeline has the capability to transmit 500 MMSCFD of "dense phase" gas, which represents a margin of 100% over the average throughput of 250 MMSCFD. Should the system be required to transmit greater quantities of gas, then the following indicative line sizes may be considered (assuming identical pipeline routing and inlet/outlet pressures of 2,700/1,500 psig as for the 24" line):

Line Size	Peak Throughput (MMSCFD)
24"	500 (2.00; 1.00)
28"	750 (3.00; 1.50)
30"	890 (3.56; 1.78)
32"	1,070 (4.28; 2.14)

Data in parenthesis are the multipliers of peak throughput on the average Hibernia throughput of 250 MMSCFD and on the capacity of the 250 mile, 24" line respectively.

As for the longer southern route, economic benefits may accrue from the installations of an oversize line where additional quantities of gas are anticipated in the future. However, given the 500 MMSCFD capacity of the line, the spare capacity at any point in time will be 70 MMSCFD higher than the 330 mile, 24" southern line thereby introducing greater scope for utilisation of spare capacity.

The application of multiple pipeline systems for the northern route will be similar to that described for the southern route in Section 7.2.2, i.e., 1 x 24" = 2 x 18" = 3 x 16".

7.10 CRITICAL AREAS OF THE GAS TRANSMISSION SYSTEM

The design, fabrication and installation of a 24" diameter high pressure gas line for Hibernia, excluding deep trenching/burial, is considered feasible. Water depths are not excessive for this size of pipe and although environmental conditions encountered will be severe they are not exceptional in the offshore industry.

The most critical, and controversial, aspect of the system remains quantification of the necessity for, and extent of, protection from the risk of damage by iceberg scour. It is not within the scope of this preliminary investigation to resolve this aspect since this requires:

i) Detailed statistical evaluation of the risk in both technical and economic terms;
ii) Detailed knowledge of the engineering properties of the soils along the pipeline route;
iii) Definition of the limiting level of risk which is economically acceptable and in keeping with good offshore practice.

It is considered likely that selection of any route into Trepassey Bay and any point east on the Avalon Peninsula, e.g. Bay Bulls, will result in untrenched, exposed pipe on the seabed and that whatever advantage is taken of topographical features the risk of rupture by iceberg scour will remain. Prediction of the extent of exposed pipe requires detailed investigation for any particular route.

The adoption of an extreme southerly route achieves the objective of maximizing the potential for trenching in the Tertiary soils which arise south of approximately latitude 46° 15'N. In the absence of detailed soils data this remains potential only, and is obtained at considerable cost compared to a more direct offshore route to, say, Bay Bulls (e.g., requiring a line length of 260 miles compared to 195 miles). The potential for trenching through the Avalon Channel may be obtained at even greater cost through the selection of a 360 mile submarine route to Placentia Bay.

There is some evidence to suggest that an exposed pipeline on a southerly route is at greater risk to scouring damage compared to a more northerly route due to the shallower water depths encountered in the Avalon Channel to the south. The relative and absolute levels of risk may only be established by detailed study, additional data collection and quantification of icebereg scouring behaviour.

In overall terms, an iceberg scour design criterion should be established, such as, say, the 50 or 100 year iceberg scour depth in particular soils along a particular route, in order to evaluate the technical, economic and operational feasibility and acceptability of the route and to establish the requirements for depth of cover, suitable trenching equipment and the number of passes of the equipment required to achieve the specified depth of cover.

Trenching in rock by blasting over considerable distances is not considered practical for reasons of high cost and slow rate of trenching. Further, it is considered unlikely that suitable mechanical trenchers for hard rock will be developed in the near future, if at all feasible.

Conventional trenching by, say, jetting, or by recently developed mechanical trenchers, will readily handle the thin layers of sand and gravel which overlie the "bedrock" on the Grand Banks. The suitability of particular equipment and the depth of cover achievable in the "bedrock" should be the subject of detailed investigation since it appears reasonable at this time to assume trenching may be achieved (to an undefined extent) using available equipment in such soils. Such an investigation will require detailed soils engineering data not available at this time.

With the exception of trenching, other critical areas associated with the gas transmission system are few since the water depths and line size envisaged are well within the capabilities of the offshore pipelining industry. The landline should present no particular difficulties other than the extent of rock grading/ditching and the number of creek/river crossings which may be encountered. The landline system is likely to be high cost but is technically feasible.

Critical areas requiring resolution at this time relate to the availability of suitable data to permit a preferred route to be selected and to allow basic engineering to proceed. Such areas include:

i) Definition of the required landed gas specification (which influences not only pipeline design but also the offshore process facilities, and which in turn depends on the onshore utilization of gas and NGL's).

ii) Selection of alternative sites for onshore gas processing facilities and potential landfalls for the submarine gas pipeline.

iii) Determination of average and peak gas throughputs as a result of detailed reservoir evaluation and consideration of possible additional gas quantities available from outside the Hibernia Field. Also, prediction of the variation in throughput over the life of the system, in particular minimum turn-down, is required.

iv) Collection, correlation and formatting of environmental and seabed survey data, and data on marine activities, for alternative pipeline routes suitable for use in:

- selecting the preferred route
- carrying out basic engineering
- evaluating trenching potential
- carrying out operational simulation of the submarine pipeline construction activity to select laybarge type and to predict laying schedules and overall cost.

The interfacing of the main gas pipeline with the FPP production deck via the Riser and the Riser Manifold Base will require considerable engineering development but is considered to be a reasonable extension of existing technology at this time. It is essential that the pipeline/FPP interface be part of the integrated design of the subsea systems requirements. Given the development concept as adopted for Study purposes, the following areas will be critical in this respect:

i) The extent of other production functions in addition to gas export which require to be integrated into the riser system at Hibernia South (which may require the use of multiple as opposed to single risers).

ii) The arrangements made for pigging/sphering of the main gas pipeline through the possible development of a subsea pig/sphere launching system.

iii) The design of high pressure connections for the gas systems (export and injection).

No similar FPF development of the magnitude required at Hibernia currently exists and for this reason there will be a high requirement for innovative design. The inclusion of a gas export capability into the overall system is not seen as a limiting factor, the success of the FPF development concept not being particularly dependent on the inclusion of the incremental facilities required for gas transmission.

In summary, the integration of gas transmission facilities with the Floating Production Facilities is considered technically feasible, although considerable engineering development will be required for the Riser and Riser Manifold Base systems as a result of the high throughput required and the extent of other production systems involved in their design and engineering. Deep trenching of the submarine gas pipeline will require further detailed investigation. The inclusion of gas export in the Hibernia development plan must be based on detailed techno/economic evaluation of the total development, which must include the risk and cost of pipeline damage and incorporate lost or deferred production of both oil and gas as a result of pipeline damage. Acceptable levels of risk will be the responsibility of the operator to define and justify based on available data and information.

Since the rupture of a submarine gas pipeline is not a considerable environmental risk, the acceptable level of risk may resolve to development economics and regulatory approval. The operational "inconvenience" of frequent rupture must be borne in mind but oil production may continue as long as gas can be re-injected during the gas transmission system shutdown. If after a number of years, re-injection is no longer acceptable due to unfavourable reservoir effects, then regulatory contraints on flaring may have a significant economic effect if oil production must be reduced or shutdown during the gas system shutdown.

SECTION 8

DEVELOPMENT PLAN/SCHEDULE

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8.0 DEVELOPMENT PLAN/SCHEDULE

8.1 BASIS FOR THE DEVELOPMENT PLAN

The principal emphasis of the Study is the southern pipeline route to Long Harbour via Trepassey Bay. Brief consideration of the scheduling aspects of a more northerly route via Bay Bulls is included in Section 8.4.

8.1.1 General Premises

The principal purpose in considering the overall development plan for the Hibernia Field is to determine whether the submarine gas pipeline and landline constitute a critical area from a project scheduling aspect.

In devising the overall development plan, a number of basic assumptions have been made concerning individual activities and the methods by which they are carried out. The plan devised is not based on firm design concepts, detailed engineering or a preferred construction/installation approach, but rather is considered representative of the overall durations and phasing which may arise.

In particular commencement of the project phase of the development cannot be defined at this time since it is subject to the finalization of the development plan by the operators, approval by regulatory authorities and final "decision to go" by the partners in the development. Thus, in the conceptual field development schedule presented in Section 8.2, the possible date of commencement of the project phase, which is indicated as mid-1983, cannot be considered in any way certain and is provided as an aid to interpretation of the schedule only.

The overall schedule comprises two main components:

i) The Pre-Project Phase; and
ii) The Project Phase

These phases are discussed below.

8.1.2 Pre-Project Phase

The pre-project phase includes all the Field Development Planning activities which lead to the final decision to proceed with the development and to commit the partners to funding major construction/fabrication contracts. It includes all appraisal/delineation drilling, reservoir analysis and preliminary studies and surveys necessary to permit the alternative development options to be evaluated and the preferred development route selected. It also includes the preparation of the development submission to be made for government approval and the approval procedure itself.

The expected submission date of the development plan by the operator is not known but has been assumed as mid-1982 for Study purposes. The stated approval process duration of eight months has then been scheduled with a four month allowance for delays. It has been assumed that six months after approval, following final basic engineering, the commitment would be made to major contracts. At this time, the possible need for additional delineation wells and reservoir analysis, the unknown status of the operator's field development plan and its submission date, and the uncertainty concerning the duration required for government approval, cannot be incorporated into the conceptual schedule. With these provisos, government approval is assumed to be mid-1983 and marks the commencement of the project phase.

8.1.3 Project Phase

Due to the complex nature of the development, it is anticipated that considerable systems design and basic engineering of the overall development concept will have been carried out to ensure the integration of all key component parts. Further, the bid cycle through which the principal detailed design, engineering and project management services contractors will be selected will have been carried out and preliminary reservation of FPP construction yard capacity may have been made. Detailed design may therefore commence early in the Project Phase but this may be delayed if extensive additional basic engineering is required following government approval to proceed.

It is important to note that the overall duration of the schedule is significantly influenced by the need for and adopted method of excavating "glory holes", followed by installation of CMC's and pre-drilling of wells. The durations of other activities therefore tend to make use of available time to achieve a reasonable construction/installation schedule but are not necessarily minimum times. Alternative subsea equipment protection methods and techniques, as well as detailed planning, may permit some compression of the overall schedule.

Key assumptions made concerning the principal programme areas are defined below.

.1 Floating Production Facilities

With regard to the FPP topside equipment, this is assumed to lead overall FPP design, starting in the order of nine to 12 months prior to commencement of procurement. Overall procurement, supply and dockside installation of equipment for one FPP is assumed to take 36 months, followed by six months pre-commissioning.

With regard to the FPP semi-submersible support structures, procurement is assumed to commence six months after detailed design begins. The overall procurement, supply and hull construction of one FPP is assumed to take 24 months to float out, two FPP's being built simultaneously.

Detailed design of all subsea systems, i.e., Risers, Riser Handling Systems, Riser Manifold Bases and Clustered Manifold Centres, is integrated and extensive and assumed to take 16 months prior to commencement of construction.

Supply of single Riser and Riser Handling System, a Clustered Manifold Centre or a Riser Manifold Base is assumed to take 18 months.

Design of the in-field flowlines and transfer lines is assumed to take six months in conjunction with other subsea systems. It is assumed that 12 months may be necessary to establish a suitable fabrication, wrapping and coating site, which may be incorporated with the wrap and coat yard for the main submarine gas pipeline. Flowlines/transfer lines would be manufactured/fabricated and coated as required with sufficient lead time for laying each season.

The crude oil storage system is assumed to be based on the conversion of suitable oil tankers with a supply duration of 18 months, including shuttle tanker mooring/loading systems.

.2 Offshore Construction/Installation (FPF's)

A basic six month "weather window" has been assumed, May to October.

The CMC's and Riser Bases, including the oil storage and mooring/loading terminal bases, are assumed to be located in seabed excavations ("glory holes"). One "glory hole" is assumed to be completed in one season by one excavation vessel. Four excavation vessels are included to permit the CMC's to be installed with reasonable lead time to allow pre-drilling prior to the availability of the FPP's. The excavation vessels are assumed to be purpose-built by others for contract to the project, with 18 months lead time to supply.

Load-out and installation of a CMC or a Riser Base is assumed to require one month and are installed, as produced, over several seasons.

In-field flowlines and transfer lines are also assumed to be laid, tied-in and trenched over several seasons, the approach and detailed schedule depending on the CMC/Riser Base schedule and the availability of construction vessels in the Field. Similarly, FPP anchor piles, if required, are installed over several seasons.

To accomplish the extensive subsea installation required, including tie-ins and piling, a semi-submersible drilling rig is assumed to be available within the Field for such work.

Installation and hot commissioning of each FPP and associated subsea systems is assumed to require three months.

.3 Gas Transmission System

Final study and route selection for the submarine gas pipeline and detailed subsea route and landfall survey is assumed to take place within 12 months, including one weather window.

Detailed design of the system is assumed to take nine months, procurement activity commencing after three months.

Twelve months is assumed for preparation of the pipe wrap and coat yard, sufficient pipe being coated and stockpiled prior to commencement of laying to enable uninterrupted laying operations during each season. The pipeyard is assumed to have two work lines each with the capability to wrap and coat 40 x 40 ft. pipe joints per day.

A large, third-generation semi-submersible laybarge is assumed to be required having the capability of laying 24" coated pipe at a rate of two miles per average lay day. Downtime for weather, mechanical break-down and non-productive operations is assumed to average 40% over the six month "weather window".

An allowance for trenching by jetting is assumed for 200 miles of the 260 mile submarine line, the remainder being untrenched. A small, semi-submersible trench barge is assumed having the capability to trench at a rate of 1.5 miles per average trench day. Downtime for weather, mechanical break-down and non-productive operations is assumed to average 50% over the six month "weather window". (Note: The feasibility of trenching and the requirement for alternative protection methods cannot be established without detailed investigation.) The allowance includes only for "conventional" trenching and is shown for information, subject to feasibility.

Post-lay survey, remedial work, hydrotest and tie-in to the Hibernia South Riser Manifold Base is assumed to require six months. Commissioning will be integrated with the start-up of Hibernia South and is assumed to require two months.

For the landline and gas reception facilities, studies, surveys and detailed design are assumed to be integrated with the submarine gas pipeline into an overall pipeline project. For the landline, an onshore laying season of six months is assumed, May to October. The whole 70 miles of the landline track is assumed to be prepared (i.e., graded, ditched, etc.) in one season with laying and back-fill also requiring one subsequent season.

The construction of the Long Harbour gas reception facilities, which do not include gas processing, is assumed to take a minimum 18 months from commencement of procurement activity.

8.2 OVERALL CONCEPTUAL FIELD DEVELOPMENT PLAN/SCHEDULE

Based on the key assumptions defined in Section 8.1, the Hibernia Field Conceptual Field Development Schedule devised for Study purposes is shown in Figure 8-1.

It is re-emphasized that the calendar years shown in Figure 8-1 are provided as an aid to interpretation only, the Hibernia project phase commencement date being unknown and unpredictable at this time. Further, construction of the Floating Production Facilities tends to indicate utilization of available time and detailed planning may result in reduced durations for certain items.

No allowances have been built into the schedule for above average, unforeseen delays or contingencies in design, construction, installation, hook-up and commissioning of the system. While some delays and contingencies may be absorbed within the overall schedule, e.g., possible extended "weather windows", the overall schedule should be considered a realistic minimum to average plan at this level of investigation.

The overall project schedule is fundamentally influenced by the assumed requirement to provide "glory hole" protection for subsea equipment. Given the utilization of a clamshell grab dredge system which is relatively slow, and the need to purpose-build several such systems, the first two CMC's cannot be installed until the "weather window" of the third to fourth project year. Assuming that these CMC's have well targets in the Avalon zone and assuming a minimum average drilling duration for deviated wells in the Avalon zone of, say, 44 days, a period of 18 months may be required to drill one 12-slot Avalon CMC (assuming all holes drilled to depth).

On this basis insufficient wells may be available to support commencement of oil production until after the fifth year of the project.

It has been assumed that two FPP's may be constructed concurrently either in a single or in separate yards. Following completion of hull construction, the structures may be launched/floated out to an outfit quay with sufficient depth of water to permit installation of the complete marine and production topsides equipment. Following the launch of the first two FPP structures, the second two would be commenced.

It has been assumed that the first two FPP's would be allocated to the Avalon zone since Avalon North and South have full water injection capabilities but produce low gas rates. Assuming that gas injection is not immediately required for reservoir pressure maintenance, oil production may therefore commence from the Avalon zone prior to installation of Hibernia South, as long as limited flaring for a period is permitted. On this basis, the overall schedule to first oil may be achieved in the sixth year after commencement of the project.

Gas injection and the potential for gas export cannot be achieved until Hibernia South is installed and commissioned. Assuming this takes place the next season after installation of the Avalon FPP's, then the potential for re-injection or export of gas may be realized in the seventh year after commencement of the project.

Within this overall schedule, the design and construction of the gas transmission system does not constitute a critical area.

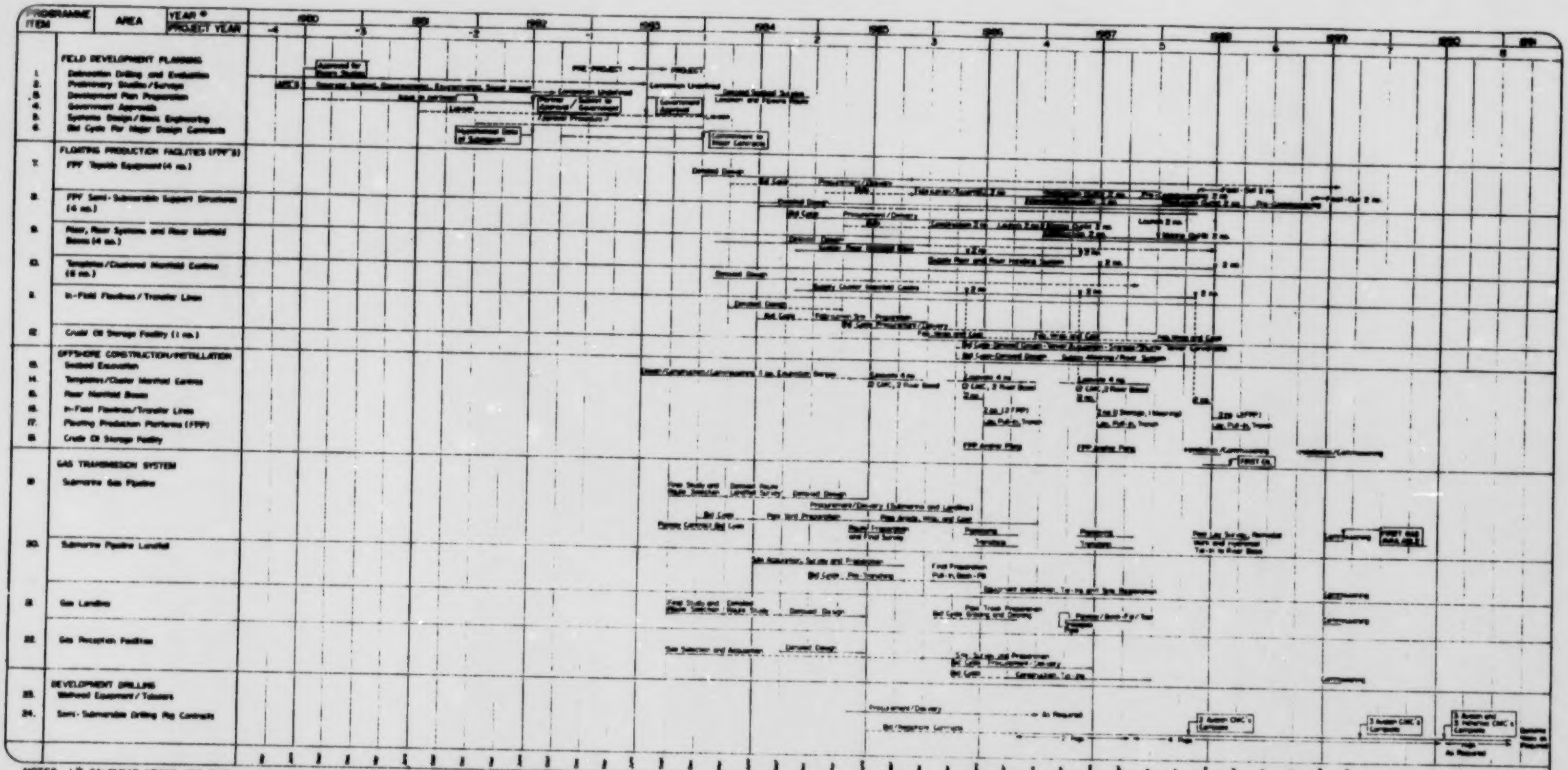
With respect to development drilling, and assuming a minimum average of 65 days per deviated well in the Hibernia zone, first two and then four rigs would be required to complete all six 12-slot CMC wells by the eighth year of the project. This includes no allowance for any satellite wells which may be required but these may be commenced in advance of CMC installation using conventional semi-submersibles. Further, the drilling of CMC wells may be slower than assumed above.

The development of Hibernia using extensive subsea production systems will require a large number of construction vessels, drilling rigs and support vessels to operate simultaneously within a relatively small sea space during the installation phase of the project. Once the first two CMC's are installed, the in-field activity will be intensive. Such operational aspects may contribute significantly to delays and/or re-scheduling of the project programme to smooth the intensity of in-field construction, installation and drilling.

Development phasing of the Hibernia Field may also offer advantages in terms of a reduced intensity of activity. The conceptual development schedule shown in Figure 8-1 assumes that the Field is to be developed to its maximum extent in a single integrated plan. Given the uncertainties relating to potential reservoir performance and the magnitude of the full development using FPF's and subsea production systems, benefits may be gained by, say, developing only the Avalon zone initially. Following production experience, development plans may be continued or extensively modified to include improved knowledge of system performance and iceberg interaction. In this way, a shorter schedule to first oil may be envisaged but a longer overall development project arises. The Hibernia Sand development would constitute a second phase of development.

Finally, with regard to the conceptual schedule devised, the project start is shown as mid-year. The schedule would be slightly modified were a year-end project start adopted in terms of utilization of "weather windows" but such differences are not significant for the purposes of this investigation and may be included in contingency allowances.

HIBERNIA FIELD - CONCEPTUAL FIELD DEVELOPMENT SCHEDULE



NOTES 1.* CALENDAR YEARS ARE GIVEN AS AN AID TO INTERPRETATION ONLY AND MUST NOT BE ASSUMED DEFINITIVE.

2. PRE-PROJECT PHASE DURATION IS HYPOTHETICAL FOR STUDY PURPOSES ONLY. DATE OF COMMENCEMENT OF PROJECT PHASE CANNOT BE DEFINED AT THIS TIME.

3. SCHEDULE INCLUDES FOR ONE STORAGE FACILITY AND ONE MOORING/LOADING TERMINAL. TWO UNITS MAY BE REQUIRED.

4. SCHEDULE AS DEVISED IS DEPENDENT ON THE TIME ASSUMED REQUIRED FOR SUBSEA EXCAVATION BY CLAMSHELL GRAB. SCHEDULED DURATIONS FOR OTHER ACTIVITIES THUS INDICATE AVAILABLE TIME AND MAY POSSIBLY BE REDUCED IF ALTERNATIVE EXCAVATION OR PROTECTION METHODS ARE ADOPTED.

Figure 8-1

8.3 GAS TRANSMISSION SYSTEM SCHEDULE

8.3.1 General

Within the overall Field development schedule as devised, the gas transmission system does not constitute a critical activity.

Following the preliminary studies and surveys carried out during the pre-project phase, the final route study and selection would be made prior to detailed survey of the preferred submarine pipeline and landline routes and the landfall and gas reception facility sites.

The detailed design of the submarine pipeline, landline, landfall and gas reception facility would comprise an integrated systems design but is not particularly complex, nine months being allowed following detailed survey activity.

Procurement of line pipe may commence three to six months after the start of detailed design, subsequent delivery schedule depending on the total tonnage of pipe, but may achieve a delivery rate of, say, 100,000 tons per quarter. Line pipe for the submarine pipeline and the landline may be similar and part of the same delivery schedule.

A period of 12 months has been allowed to establish a pipe storage wrrap and coat yard in Newfoundland, the yard requiring, say, two wrap/coat units each capable of coating, say, 40 x 40 ft. joint lengths of pipe per day.

8.3.2 Submarine Gas Pipeline and Landfall

Assuming that submarine pipelaying is to commence in the third year of the project, route preparation, i.e., submarine rock grading, landfall pre-trenching would be undertaken in the previous season, a six month period being allowed. At the commencement of the first laying season, remedial work required on the prepared route track would be undertaken, the laybarge mobilized and the first length of pipeline pulled in to shore from the laybarge. The laybarge would then proceed to lay away from the shore (this is a typical approach for commencement of laying).

Using the third generation semi-submersible laybarge, two laying seasons may be required to complete the submarine line. This includes an allowance for say one "wet" buckle and two "dry" buckles occurring requiring, say 30 days and 10 days, respectively, to repair.

Conventional trenching of the 200 miles of the submarine line which is assumed to be jet trenched may require a trench spread for two seasons.

Contingency allowances for delays in laying and trenching may be accommodated by extending the "weather window" into, say, April and November. Laying and trenching should not therefore be required for a third season.

An allowance of six months is allocated for post-lay survey, remedial work and post remedial work survey. This period may be reduced if the as-laid condition of the line is good. Tie-in to the Hibernia South Riser Manifold Base would be made using the semi-submersible rig available in the Field for construction purposes.

Commissioning of the pipeline will be integrated with the commissioning of Hibernia South and will require minimal time.

From the commencement of detailed design therefore, the submarine gas pipeline may be installed within three to four years in readiness for commissioning.

Following pull-in and back-fill of the submarine line, the landfall equipment, e.g., isolation valves, pig/sphere launcher, telecommunications, etc., would be installed and the site restored in accordance with contractual and regulatory requirements. Tie-in with the landline would be made as appropriate.

8.3.3 Gas Landline

The schedule, and cost, for laying the landline is influenced by the type of ground the line is to be laid over. It has been assumed that the line will be required to be buried but, should extensive rock ditching be required, the cost of this requirement may warrant consideration of above ground laying with pipe protection by, say, berming, if permitted.

Detailed information on the landline route is not available at this time and therefore the following assumptions have been made:

i) Rock grading will be required for eight miles of the 70 mile route.
ii) Rock ditching will be required for 60% of the route.
iii) Wet areas requiring "rip-rap" stabilization will comprise 8% of the route.
iv) Forty Creek/River crossings will be required.
v) Seven Road/Railway crossings will be required.

The above assumptions are made for Study purposes only and detailed route survey may result in considerable variation from the above.

Onshore, the best working conditions have been assumed to prevail between April and October. The philosophy has been adopted that the route will be 100% prepared in one season with all pipelaying taking place in the subsequent season. A six day work week has been assumed with an average of 20% downtime for weather and mechanical breakdown.

The overall landline construction programme therefore extends over two seasons.

8.3.4 Gas Reception Facilities

A minimum schedule of 15 months construction time has been allowed for the gas reception facilities given early site acquisition and detailed design.

The gas reception facilities are relatively simple since they do not include any gas processing facilities which is assumed to take place outside the battery limit of the gas reception site.

Construction of both the landline and the gas reception facilities may be delayed by one year if desired.

8.4 DIRECT PIPELINE ROUTE VIA BAY BULLS

Given the same planning basis as defined in Section 8.1, and the overall Field Development Plan as presented in Section 8.2 and Figure 8-1, the shorter, northern route via Bay Bulls is, axiomatically, not a critical programme item.

With respect to the submarine pipeline, a laybarge spread is required for two seasons, but for a reduced number of operating days compared to the southern route (approximately 213 days for the northern route compared to 268 days for the southern route, excluding contingencies). The flexibility of the pipelaying schedule within the overall programme is therefore increased but the full reduction in required lay days may not be realised should the contractor require a minimum hire period in the second season.

Given the assumption that the semi-submersible laybarge also constructs the in-field transfer lines (a period of 24 days being assumed, refer Appendix II, Page 11) the minimum required laying period for the barge is 237 days, 287 days including contingency allowances. When contracting major pipelaying vessels, a minimum hire duration in any one season may be specified by the contractor, say 90 days excluding mobilisation/demobilisation. Such a minimum hire period, and associated cost penalty, is not applied here although the schedule for the northern route is marginal in this respect. Final agreement on contract periods will be subject to negotiation.

With respect to trenching of the main submarine pipeline, approximately 50% of the line length (97.5 miles) is assumed potentially suitable for trenching by conventional methods. The trenching spread would therefore be required for 130 days, i.e. a single season as compared to two seasons for the longer southern route. The necessity to retain the spread for remedial work, combined with the assumption that it is also used to trench the in-field lines, will however require the spread for two seasons. Minimum hire periods may also apply but are not included here.

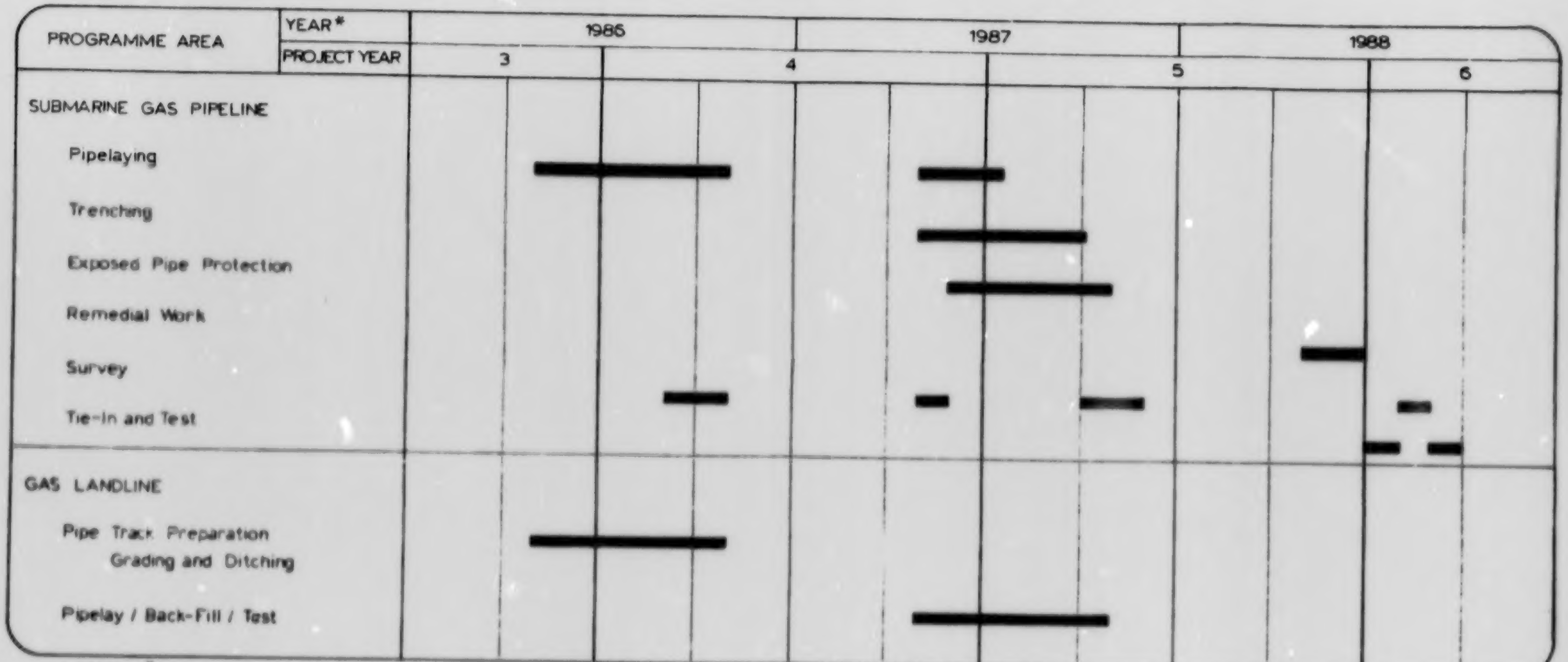
The philosophy for constructing the slightly shorter landline required, given a Bay Bulls landfall (approximately 55 miles compared to 70 miles for the Trepassey Bay route) has been to divide the activity over two seasons, as for the southern route. The schedule within each season will, therefore, be less intensive.

The relative extent of seabed prepration and post-lay pipe protection requirements for exposed pipe over the 50% of the northern route where conventional trenching is not assumed feasible, compared to that required for the assumed 60 miles of the southern route, is not quantifiable without detailed seabed survey data. It is assumed in principle that for the northern route such pre- and post- lay activity will increase while the trenching remedial work will reduce.

The northern route will therefore required the same overall pipeline construction schedule as for the southern route although the sequencing and intensiveness of the activities may alter. A possible schedule for the main gas pipeline construction is shown in Figure 8-2, all other activities being as per the overall development schedule given in Figure 8-1.

HIBERNIA FIELD - CONCEPTUAL FIELD DEVELOPMENT SCHEDULE

Hibernia - Bay Bulls - Long Harbour Route - Pipeline Construction Schedule



NOTES: 1 *CALENDAR YEARS ARE GIVEN AS AN AID TO INTERPRETATION ONLY AND MUST NOT BE ASSUMED DEFINITIVE

2 CONTINGENCIES INCLUDED IN DURATIONS.

3 ALL OTHER FIELD DEVELOPMENT ACTIVITIES ARE AS PER THE OVERALL FIELD DEVELOPMENT SCHEDULE (REFER FIGURE 8-1)

J31-1/7575

FIGURE 8-2

8.5 CRITICAL AREAS OF THE DEVELOPMENT PLAN

The conceptual Field development plan/schedule devised for Study purposes is intended to give an overview of the possible duration of the project and to determine whether the gas export system will impose any critical construction constraints on the overall programme.

The overall duration of the project is significantly influenced by the assumed need for major seabed excavations to protect subsea equipment. The scheduling of other items is then integrated with the assumed earliest completion of CMC and Riser Manifold Base installation. The durations shown for the Floating Production Facilities therefore tend to indicate utilization of available time and are not necessarily minimum schedules. For example, the elimination of extensive excavation may reduce the overall programme by, say, 12 months. Such reduction would require more detailed definition and planning of the design, engineering and construction effort required than is available at this preliminary investigation stage. This is particularly so for the semi-submersible support structures, topsides facilities and subsea systems.

The conceptual schedule indicates an extensive overall duration, and hence high inflation risk. The duration depends not only on increased technical definition but also on source of materials, equipment supply and location and productivity of construction sites. It is outside the scope of this Study to consider the influence on the schedule of maximizing Newfoundland, or Canadian content with respect to supply and construction. Delays or contingencies which may thereby arise are not included in the schedule.

Such factors should be the subject of detailed investigation including the comparison of typical international supply lead times and durations with possible Newfoundland or Canadian alternatives.

As previously mentioned, the source of supply and location of construction sites on the international market will also significantly influence the schedule and hence the durations indicated on the schedule tend to be conservative. Most critical in this respect will be the early commitment to a construction yard for the FPP's and the commitment to a large, semi-submersible laybarge (if this is the preferred vessel type for pipeline construction).

As highlighted on Figure 8-1, the possible date for commencement of the project cannot be defined at this time since it depends on the completeness of the operator's development plan as well as partners' and Government approval to proceed.

The Development Plan approval process may include a period of eight months from submission of the development plan to complete or partial approval to proceed. Should the plan prove unacceptable, considerable delay may arise in project commencement as discussions proceed and revisions are made, followed by re-submission of the plan and a repeat of the approval procedure.

Further, the status of the operator's preliminary studies, particularly reservoir definition, is not known and hence the overall duration of the pre-project phase is not well defined at this time.

The calendar dates for submission of the development plan and approval by government indicated on Figure 8-1 are therefore conceptual for study purposes, the calendar years being provided only as an aid to interpretation without knowledge of or prejudice to the eventual schedule which may arise.

Assuming that trenching of the main submarine gas pipeline is required only to conventional depths, and that soils on the Grand Banks are suitable for conventional equipment, the offshore pipeline construction programme indicated for either the southern or northern route adopted is not critical within the overall schedule and should not become so even with, say, 12 months compression of the overall schedule. Selection of a route longer than the 260 mile southern line would require revision of the schedule. In any event, gas export need not be considered to commence with first oil production if either re-injection is available or flaring is initially permitted to allow a safe and sensible construction and commissioning schedule to be devised. Further, if gas export is not required for some years after first oil, construction of the pipeline may be scheduled as a second phase of development later in the life of the Field.

Should the soils of the Grand Banks prove difficult for conventional trenching, the allowance included in the schedule may increase significantly as the trench production rate per mile falls, say as the result of multiple passes being required with a jet sled over a considerable length of the line. Trenching over considerable distances in the hard rock of the Avalon Channel is considered not feasible at this time and remains excluded from the schedule.

Finally, the conceptual schedule as devised assumes the integrated development of the total resource and does not include any consideration of phased development other than to assume that only two FPP's should be installed each season to allow reasonable scheduling of construction and installation.

SECTION 9

CAPITAL AND OPERATING COST ASSESSMENT

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9.0 CAPITAL AND OPERATING COST ASSESSMENT

The principal emphasis of the Study is the southern pipeline route to Long Harbour via Trepassey Bay and it is this route to which the information presented in Sections 9.2 through 9.3 refers. Brief consideration of the cost aspects of a more northerly route via Bay Bulls is included in Section 9.5.

9.1 BASIS FOR COST ASSESSMENT

9.1.1 General

The datum for cost assessment is 1st January, 1982.

Costs have been substantially based on North Sea project costs since it is assumed that, in general, market forces will tend to determine the supply of materials, equipment and services.

With regard to major capital items, e.g., semi-submersible FPP's which may be constructed in Canada, if appropriate and practical, no allowances have been made for the possible upgrading of existing yards/manufacturing sites, or for the possible establishment of new facilities within Canada, as compared with reasonable international supply costs. Clearly, even given international supply, quotations for similar items from different countries will cover a wide range, e.g., rig construction in Korea versus Norway. Current cost differentials between Canada and Norway, for example for rig supply are understood to be in the order of 10% in Norway's favour. However, no allowance has been made for such items as productivity differentials in the assessment since the magnitude of this will depend on the extent of "Canadianization" achieved within the project.

The assessment made relates to the project cost elements only and thus excludes:

i) Pre-Project Costs
ii) Development Drilling Costs
iii) Taxation

With reference to development drilling, the assessment includes an allowance for the supply of "above the mudline" wellhead equipment directly associated with either the CMC's or satellite wells. No tubulars, downhole equipment or other consumables are allowed for, this being part of development drilling. Further, the installation of satellite well templates, etc., is assumed to be included in development drilling, but an allowance is made for installation and tie-in of satellite well flowline bundles.

No allowance is made for the effects of inflation on materials, labour and supply of services over the life of the project (which is likely to be a significant item and depends on inflation rates and cash flow phasing). Based on the project programme set out in Section 8, a project cost cash flow profile is given in Section 9.4 to enable the Petroleum Directorate to estimate inflation using appropriate indices.

Contingency allowances to cover lack of project definition at the preliminary investigation stage, estimating shortfalls, items omitted and reasonable unscheduled delays and downtime due to problems and weather, have been made as follows:

i) 30% on support structures, topsides facilities, subsea equipment and risers, in-field flowlines/transfer lines;
ii) 20% on submarine pipeline, onshore gas reception facilities;
iii) 10% on landline.

The following allowances have been made to cover elements not estimated by more detailed breakdown:

i) Allowances to cover management, supervision, design and engineering:

- 12% on support structures, topside facilities, subsea equipment and risers, in-field flowlines/transfer lines, onshore gas reception facilities;
- 6% on submarine pipeline, landline.

ii) Insurance: 3% offshore to cover insurance of capital equipment (excluding development drilling), 2% onshore.

iii) Commissioning:

- 5% on installed cost of support structures, topside facilities, subsea equipment and risers, in-field flowlines/transfer lines, onshore gas reception facilities;
- 2-1/2% on installed cost of submarine pipeline, landline.

9.1.2 Submarine Gas Pipeline

The following is a schedule of key rates used in the compilation of the submarine gas pipeline cost assessment:

i)	Line Pipe Material; 24", API 5LX 60	$1,400/long ton
ii)	Line Pipe Wastage/Deviation Allowance	5% total length
iii)	Valves, Fittings, Buckle Arrestors, etc.	5% line pipe material cost
iv)	Line Pipe Anodes, Wrapping and Concrete Coating	$20/ft.
v)	Pipe Handling, Storage	$10/ft.
vi)	Pipe Supply Vessels (1,500-2,000 ton dwt)	$10,000/day
vii)	Third Generation Large Semi-Submersible Pipelaying Spread including all services, fuel	$300,000/day
viii)	Pipe Trenching Spread (Small Semi-Submersible Laybarge) including all services, fuel	$250,000/day
ix)	Survey vessel including Diving Spread, RCV/Sub	$80,000/day

9.1.3 Offshore Installation (Offshore Structures and Facilities)

The following is a schedule of key rates used in the compilation of offshore installation cost assessment:

i)	Survey Vessel	$ 30,000/day
ii)	Ocean-Going Tugs/Supply Vessel	$ 10,000/day
iii)	Diving Spread (including RCV/Submersible)	$ 80,000/day
iv)	CMC/Riser Base Installation/Piling/ Tie-in Spread (Semi-Submersible Drilling Rig) including Basic Services	$125,000/day
v)	Safety Vessels	$ 6,000/day
vi)	Helicopters (3 hrs. per trip)	$ 3,000/hour
vii)	Seabed Excavation Spread	$ 65,000/day
viii)	Cargo Barge	$ 5,000/day
ix)	Additional Equipment for Piling/ Cementing, etc.	$ 50,000/day

9.1.4 Gas Landline

The following is a schedule of key rates used in the compilation of the gas landline cost assessment:

i)	Line Pipe Material; 24", API 5LX 60	$1,400/ton
ii)	Line Pipe Wastage/Deviation	5% total length
iii)	Valves, Fittings, Misc. Equipment	5% line pipe material cost
iv)	External/Internal Coating, Corrosion Protection	$7/ft.
v)	Stockpiling Pipe	$5/ft.

vi)	Route Preparation	
	Clearing, Access Roads	$27,500/mile
	Common Grading/Culverts	$40,000/mile
	Rock Grading (8 miles)	$490,000/mile
	Rock Ditching (60% total length)	$268,000/mile
vii)	Pipelaying, Backfill and Test	$560,000/mile
viii)	Creek/River Crossings (40 No.)	$500,000/each
ix)	Road/Railway Crossings (7 No.)	$90,000/each

9.2 OVERALL PROJECT COSTS - INCLUDING SOUTHERN PIPELINE ROUTE

9.2.1 Summary

A summary of the overall Project Budget for the Hibernia development, including a 330 mile, 24" pipeline via Trepassey Bay, is given in Table 9-1.

The Project Budget excludes pre-project costs and development drilling and indicates a capital cost in the order of $5.06 Billion including contingencies of approximately 28% of the Base Project Cost.

Pre-project costs will depend on existing exploration/delineation costs expended, the number of appraisal wells yet to be drilled, and the necessity for additional studies prior to achieving partner and government approval to proceed. For illustration purposes only, pre-project costs may be in the order of $400 MM to $500 MM.

Development drilling costs will depend on the number of producers and injection wells required to efficiently deplete the reservoir and must include an allowance for dry/junked holes. The Project Budget, as prepared, includes the potential for 88 wells to be drilled. For illustration purposes only, assuming such a number of wells were to be drilled, then drilling costs based on contracting rigs may be in the order of $2,000 MM, excluding wellhead/ completion equipment which is included in the Project Budget.

Subject to the above, the total Field Development Budget for Hibernia, including gas transmission to shore, would be in the order of $7.51 Billion in 1.1.1982 terms.

The Project Budget is based on contracting a significant number of construction and support vessels for the 3 to 4 year period of offshore work. Savings may be realized through the purchase of vessels/barges for the Hibernia development. Such savings have not been investigated here but would be worthy of consideration, particularly with regard to the semi-submersible drilling rig considered necessary for construction purposes. Since at least one, probably two, well workover rigs will be required, benefit may be realized through the early acquisition of such rigs for both construction and pre-drilling use.

9.2.2 General Commentary

There are many uncertainties in estimating frontier system costs: logistics problems, technical innovations, construction season limitations, labour problems, government controls associated with high profile projects and inadequate project management capabilities all combine to form a wide distribution of possible costs, regardless of the quality of the preliminary estimates. Unit development costs are often particularly sensitive to economies of scale due to development infrastructure requirements - e.g., roads, air strips, fabrication yards, construction camps, etc. It should also be noted that an alternative engineering approach may completely revise the costs projected for the Hibernia area in this preliminary investigation.

The problem of design approach is in part related to the stage of development of a basin. The first systems put on stream will carry a disproportionate share of infra-structure costs and may be more conservatively designed. Another factor which impacts on costs is fiscal regimes which may provide little incentive for cost control or reduction.

Since the Hibernia development may be the first Canadian offshore development project, some of the cost elements are based on extrapolations of North Sea experience, where labour costs, productivities and environmental controls are different from those anticipated in Canada. Sourcing of the materials and construction force is uncertain. Newfoundland is lacking in a large population base and construction infra-structure and any requirement for the use of Newfoundland or other Canadian based industry to the exclusion of competitive sources in other parts of the world, could certainly impact cost. No allowance has been made for these aspects, however.

Probably the most important element in the cost estimate provided is the nature of the reservoir to be developed. Pay thickness, areal extent and oil characteristics all will have a significant effect on development costs for the Hibernia area, the major uncertainty being well productivity. Until delineation of the Hibernia structure is complete and preliminary studies, data collection, cost estimates and economics are examined, the final development scheme will not be decided upon. The choice of system (or combinations of different types of systems) will ultimately depend on capital exposure, operating costs and risks, hydrocarbon recoveries, profitability and timing.

The presence of pack-ice and icebergs in the Hibernia area, however, limits the number of systems which should be considered to subsea wells with floating facilities, or to artificial islands, or to combinations of these systems. The large fixed structures typical of the North Sea may have to be removed from serious consideration due to ice conditions. The possibility of constructing artificial islands or berm-protected structures to resist iceberg damage is an alternative which faces high costs, long construction periods and environmental disturbance, but offers lower well capital and operating costs and higher recoveries than subsea systems. Well producibility, oil quality, reservoir area, configuration and pay thickness will all have an influence on the decision.

However, based on currently available information on reservoir quality, it appears that the type of facility which is most likely to be utilized in one form or another for production in the Hibernia area, consists of subsea completed wells producing to a floating production structure similar to the concept adopted for Study purposes. Development technology in the last several years has been moving toward this type of facility, which is capable of early production, as wells can be drilled prior to floating platform and processing facility installation. These systems have been proposed only for marginal fields at this time; the higher operating costs and interruptible nature of the production would result in marginally lower oil recoveries. Development of a field the size of Hibernia would certainly be a significant breakthrough for this type of system. In this regard, with the possible exception of an artificial island structure, little choice exists for the operator. The alternative to iceberg and pack-ice resistance is avoidance; a floating structure would be capable of moving off location in the event of iceberg danger, or heavy pack-ice incursion, and it seems probable at this time that this type of system would be used in this area.

9.2.3 Project Budget Assessment

For Study purposes, the development has been subdivided into four main areas as follows:

i) Offshore Structures and Facilities
ii) Submarine Gas Pipeline
iii) Onshore Gas Landline
iv) Onshore Gas Reception Facilities

The individual Project Budget assessment for each of these areas is given in Tables 9-2 through 9-5, and is summarized as follows:

	Project Budget, $MM
Area	1.1.82
Offshore Structures and Facilities	4,121.88
Submarine Gas Pipeline (260 mile)	741.86
Onshore Gas Landline (70 mile)	165.86
Onshore Gas Reception Facilities	28.56
TOTAL	5,058.16

It should be noted that apart from the Remote Mooring/Loading Terminals for shuttle tanker which are included in the Project Budget, all costs associated with Shuttle Tankers, including any allowance for minor conversion, is included in the Operating Costs defined in Section 9.2.4 as part of the Crude Oil Export Tariff.

TABLE 9-2 OFFSHORE STRUCTURES AND FACILITIES - CAPITAL COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

OFFSHORE STRUCTURES AND FACILITIES PROJECT BUDGET

		ITEM	Cost, $MM 1.1.82
1.		Structure/Facilities Supply	
	A.	Semi-Submersible Support Structures (4 No.)	600.00
	B.	Topside Facilities (Installed at Dockside)	297.58
	C.	Oil Storage/Mooring/Loading Systems (2MM Bbls)	350.00
	D.	Riser Manifold Bases (4 No.)	60.00
	E.	Risers/Riser Handling Systems (4 No.)	65.00
	F.	Cluster Manifold Centres (6 No.)	84.00
	G.	Subsea Equipment Control Systems (4 No.)	48.00
	H.	Wellhead/Completion Equipment (88 wells)	304.00
	I.	CMC to Riser Manifold Base Flowline Bundles (12 No.)	36.00
	J.	In-Field Transfer Lines (35 miles)	8.05
	K.	Satellite Well Flowline Bundles (20 No.)	30.00
	L.	Semi-Submersible FPP Anchor Piles (48 No.)	0.72
	M.	CMC/Riser Base Piles (60 No.)	0.60
		Structure/Facilities Supply Sub-Total	1,883.95
2.		Offshore Construction/Installation	
	A.	General Allowances for Work Vessels, etc. (3-4 Years)	
		i) Semi-Submersible Drilling Rig	140.88
		ii) Survey Vessels/Diving Spread	65.10
		iii) Safety/Supply Vessels, Helicopters	87.70
		iv) Misc., Bases and Depots	50.00
		General Allowances Sub-Total	343.68

Cont'd/ ...

TABLE 9-2 OFFSHORE STRUCTURES AND FACILITIES - CAPITAL COST ASSESSMENT (Cont'd.)

	B.	Seabed Excavations	287.95
	C.	CMC/Riser Manifold Bases	28.00
	D.	FPP Anchor Piles	9.60
	E.	CMC to Riser Manifold Base and Satellite Well Bundles	12.92
	F.	In-Field Transfer Lines	19.25
	G.	Oil Storage/Export Systems	54.60
	H.	Floating Production Platforms (Towage)	2.28
		Offshore Construction/Installation Sub-Total	758.28
3.	Management, etc.		
	A.	Mgt., Supervision, Design, Eng. (12%)	317.07
	B.	Commissioning/Start-up (5%)	132.11
	C.	Insurance (3%)	79.27
		Management, etc. Sub-Total	528.45
		Base Cost	3,170.68
4.	Contingency (30%)		951.20
		Project Budget	4,121.88

Notes: 1. Project Budget Excludes Pre-Project Costs And Development Drilling Costs.

2. All Costs Are Base 1.1.1982 With No Allowance For The Effects Of Inflation.

TABLE 9-3 SUBMARINE GAS PIPELINE - CAPITAL COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

SUBMARINE GAS PIPELINE PROJECT BUDGET - HIBERNIA TO TREPASSEY BAY

		ITEM	Cost, $MM 1.1.82
1.		Materials	204.78
2.		Construction	
	A.	Pre-Laying Activities	41.61
	B.	Landfall	30.00
	C.	Pipelaying/Pipe Supply (260 miles)	129.12
	D.	Trenching (Refer to Note 1)	97.00
	E.	Post-Lay Activities	49.70
	F.	Tie-ins	2.25
		Construction Sub-Total	349.68
3.		Management, etc.	
	A.	Mgt., Supervision, Design, Eng. (6%)	33.27
	B.	Test/Commissioning/Start-up (2-1/2%)	13.86
	C.	Insurance (3%)	16.63
		Management, etc. Sub-Total	63.76
		Base Cost	618.22
4.		Contingency (20%)	123.64
		Project Budget	741.86

Notes:

1. Indicative Allowance For Trenching Is For Conventional Offshore Trenching To, Typically, 3 Ft. Cover Over 200 Miles Of The 260 Mile Pipeline. No Allowance Is Made For Deep Burial Over This Length, Or For Burial In Rock Zones In The Avalon Channel Beyond The Landfall.
2. Project Budget Excludes Pre-Project Costs.
3. All Costs Are Base 1.1.1982 With No Allowance For The Effects Of Inflation.

TABLE 9-4 ONSHORE GAS LANDLINE - CAPITAL COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

ONSHORE GAS LANDLINE PROJECT BUDGET - TREPASSEY BAY TO LONG HARBOUR

	ITEM	Cost, $MM 1.1.82
1.	Materials	50.09
2.	Construction (70 miles)	
	A. Route Preparation	24.59
	B. Pipelaying	61.77
	Construction Sub-Total	86.36
3.	Management, etc.	
	A. Mgt., Supervision, Design, Eng. (6%)	8.19
	B. Test/Commissioning, Start-up (2-1/2%)	3.41
	C. Insurance (2%)	2.73
	Management, etc. Sub-Total	14.33
	Base Cost	150.78
4.	Contingency (10%)	15.08
	Project Budget	165.86

Notes:
1. Project Budget Excludes Pre-Project Costs.
2. All Costs Are Base 1.1.1982 With No Allowance For The Effects Of Inflation.

TABLE 9-5 ONSHORE GAS RECEPTION FACILITIES - CAPITAL COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

ONSHORE GAS RECEPTION FACILITIES PROJECT BUDGET

	ITEM	Cost, $MM 1.1.82
1.	Supply/Construction/Installation	20.00
2.	Management, etc.	
	A. Mgt., Supervision, Design, Eng. (12%)	2.40
	B. Commissioning/Start-up (5%)	1.00
	C. Insurance (2%)	0.40
	Management, etc. Sub-Total	3.80
	Base Cost	23.80
3.	Contingency (20%)	4.76
	Project Budget	28.56

Notes: 1. Project Budget Excludes Pre-Project Costs.

2. All Costs Are Base 1.1.1982 With No Allowance For The Effects Of Inflation.

9.2.4 Operating Cost Assessment

Any estimation of operating costs made at this level of investigation are at best indications only due to lack of technical definition available and the considerable variation which can arise in operating costs from year to year.

It is considered that no better estimate can be made at this time than one based on an average percentage of total capital expenditure. In particular, due to the extent of subsea systems involved and the use of multiple floating facilities, the offshore operating costs are expected to be high.

Operating costs per key area per annum for the development, including a 330 mile pipeline via Trepassey Bay, are therefore estimated as follows:

Area	% CAPEX	Peak Year OPEX $MM p.a. (1.1.82)
Offshore Structures and Facilities	7-1/2%	309.14
Submarine Gas Pipeline (260 miles)	5%	37.09
Onshore Gas Landline (70 miles)	1%	1.66
Onshore Gas Reception Facilities	3%	0.86
TOTAL		348.75

The above relates to the production and transmission facilities only and does not include allowances for well fixed cost workovers, re-drilling or remedial work, or for crude oil transportation tariffs. Further, the operating costs given are for years of peak production and may be less in earlier years but will possibly be offset in declining years by increased maintenance costs.

Running costs per well per annum may be in the order of $300,000. Major workover costing in the order of $3 MM may be required at intervals of approximately 3 years per well.

Tanker transportation tariffs are likely to be in the range of $1 to $2 per barrel depending on destination within a 1,000 mile radius of discharge. This would, for example, permit delivery of crude to Portland, Maine, U.S.A.

9.3 GAS TRANSMISSION SYSTEM COSTS - SOUTHERN ROUTE

9.3.1 Overall System Costs

The capital and peak year operating costs of the southern gas transmission system downstream of the Riser Manifold Base have been established in Section 9.2 as follows:

Area	CAPEX, $MM 1.1.82	OPEX $MM P.A. 1.1.82
Submarine Gas Pipeline (260 miles)	741.86	37.09
Onshore Gas Landline (70 miles)	165.86	1.66
Onshore Gas Reception Facilities	28.56	0.86
TOTAL	936.28	39.61

9.3.2 Associated Offshore Equipment Costs

As discussed in Section 7.7, there are very few additional topside equipment items required at the production centres to support gas transmission. Indicative "ready to ship" costs for the principal equipment items required in addition to those required for gas re-injection are as follows for Hibernia South only:

Basic Topside Associated Equipment Cost	Cost, $MM 1.1.82
1. Gas Dehydration/Regeneration Unit	1.15
2. Gas Metering Skid	1.15
3. Pig Launching and Additional Piping, Instrumentation, Bulks	1.15
Basic Topside Associated Equipment Cost	3.45

Total installed cost of the above items is estimated overleaf.

Installed Topside Associated Equipment Cost	Cost, $MM 1.1.82
1. Material and Equipment	3.45
2. Installation (Dockside)	0.50
3. Management, Engineering, Commissioning, Insurance (20%)	0.79
Topside Associated Equipment Base Cost	4.74
4. Contingency (30%)	1.42
Topside Associated Equipment Project Budget	6.16

The gas transmission system is considered to have negligible effect on general topsides and the FPP support structure as a whole.

Given the Field Development concept adopted for Study purposes, the export of gas has no effect on the cost requirement for CMC's and In-Field Flowlines/Transfer Lines. This would not be the case were the four FPP's entirely independent production centres.

The requirement for gas transmission introduces the necessity to incorporate a gas export line, or possibly lines into the Hibernia South Riser and Riser Manifold Base, together with a possible requirement for a subsea pig launching system.

At this point of investigation a cost element for this can only be derived by factoring the overall cost estimate which has been made for all four platforms, the risers being different but equally complex on all platforms except Hibernia North (which incorporates neither water nor gas injection systems). Extracting the overall unit cost for Risers and Riser Manifold Bases yields the following basic data on an equipment only basis (since installation will be required in any event):

A. Unit Costs Including Management, etc., and Contingency:

	1.1.82
Riser Manifold Base	$23.40 MM
Riser (incl. Part of Spares)	$17.55 MM
Handling System	$ 7.80 MM
Control System (1/4 Basic System)	$ 4.68 MM
TOTAL	$53.43 MM

B. Basic Functions Served at Hibernia South:

Riser Manifold Base	Riser
Med. Pressure Gas (2 No.)	Production
Flowline Bundles (4 No.)	Production Test
Oil Export (1 in; 1 out)	TFL
Inj. Water Transfer	Med. Pressure Gas
Inj. Gas Transfer	Injection Gas
Satellite Wells (2 No.)	Control Conduit/ Cables
Gas Export	Hydraulic Supply
	Oil Export
	Gas Export

C. Relative Functional Division:

Subdivision on a functional basis is complicated by the variety of line sizes and pressures handled. Gas export is at median pressure but requires either a single large line or a number of smaller lines to handle the high gas quantities.

Assume Riser Manifold Base is modular in design and that Gas Export requires 1 module from a total, say, of 13 modules.

Assume Gas Export accounts for 15% of riser cost.

D. System Costs Attributable to Gas Export:

	1.1.82
Riser Manifold Base	$1.80 MM
Riser/Handling System/Control System	$4.50 MM
TOTAL	$6.30 MM

The above analysis is extremely approximate and serves only to demonstrate that due to the overall complexity of the riser and riser manifold systems, only a small proportion of total cost may be apportioned to gas export.

It should be noted that there will be some operational cost offset when exporting gas as opposed to re-injecting due to the shutdown of the high pressure compression trains together with a small reduction in fuel gas usage for compression.

In summary, therefore, the differential costs of exporting gas from Hibernia, given the development concept adopted for Study purposes, essentially reduces to the cost of the submarine gas pipeline, the landline and gas reception facilities, plus only a small increment estimated at $12.22 MM.

Table 9-6 presents a summary of overall gas transmission system costs including associated equipment.

TABLE 9-6 SUMMARY OF OVERALL GAS TRANSMISSION SYSTEM COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

GAS TRANSMISSION SYSTEM PROJECT BUDGET - TREPASSEY BAY LANDFALL

	ITEM	Cost Summary, $MM, 1.1.82	
		Project Budget	Peak Year OPEX
1.	Offshore FPP Associated Equipment		
	A. Topsides Facilities	6.16	0.46
	B. Riser Systems	4.50	0.34
	C. Riser Manifold Base	1.80	0.14
	Offshore FPP Associated Equipment Sub-Total	12.46	0.94
2.	Submarine Gas Pipeline (260 miles)	741.86	37.09
3.	Onshore Gas Landline (70 miles)	165.86	1.66
4.	Onshore Gas Reception Facilities	28.56	0.86
	Overall Gas Transmission System	948.74	40.55

Notes:
1. Project Budget Excludes Pre-Project And Development Drilling.
2. Submarine Pipeline Trenching Costs Included Are For Conventional Burial by Jetting Only.
3. All Costs Are 1.1.82 With No Allowance For The Effects Of Inflation.

9.3.3 Major Repairs

The estimated operating cost for the submarine pipeline includes for minor pipeline repairs but not for major repair as a result of line rupture due to impact from anchors, fishing equipment, wrecks or iceberg scour. Damage due to anchors will be reasonably localized requiring the damaged section to be uncovered (if necessary) and cut away and a spool piece installed. Welded connections are preferred as compared to mechanical type for this high pressure gas system. Iceberg scour damage, where damage over extended lengths can be envisaged, may require the laying of a new section of line, possibly hundreds of feet long. Such a length may be off-bottom towed to site or laid conventionally from a laybarge. Repair costs in the order of $5 MM to $25 MM can be envisaged depending on severity of damage.

9.3.4 Multiple Pipelines

With respect to improving security of supply given the risk of damage by iceberg scour, duplication of the main submarine gas pipeline over its entire length is not considered to be cost effective due to the high cost involved.

As discussed in Section 7.2.2, installing multiple lines which combined have the same capacity as the single line is anticipated to involve at least 50% or 100% increase in cost (for double or triple lines respectively) without any increase in throughput capacity. The improvement in security of supply so derived cannot be quantified at this time but is subjectively considered small.

Duplication of the main line will double the capacity but will incur at least twice the costs with again a subjectively small improvement in security of supply.

Of more interest may be the twinning of the main gas pipeline over relatively short distances which are particularly exposed to iceberg scour. In such a scheme, "Y" pieces would be installed at each end of the exposed length complete with isolation valves and pig diverter. The main line would then be duplicated over widely different routes across the exposed length.

For discussion purposes, it may be assumed that the additional length of pipe required to be laid between the two "Y" pieces may triple compared to the single line length being twinned.

The basic installed cost per mile of 24" pipe, derived from the southern route cost assessment (refer Appendix II) by deleting the landfall, tie-ins and trenching costs, is in the order of $2.2 MM per mile. Three subsea tie-ins will be required per "Y" piece.

Assuming, for discussion purposes, that the installed cost of each "Y" piece, including tie-ins, is $30 MM, then the total cost to twin a length "L" miles of the submarine line may cost in the order of $(3L x 2.2 + 60)MM. On this basis, twinning 60 miles of line would cost $456 MM.

A "risk-benefit" analysis is required to determine the value of incurring such a high cost and must include the compounded risk that both lines may still be damaged, possibly by the same iceberg, and that the risk of damage from other marine activity is increased. Further, should one line be damaged, the repair cost must still be expended to regain the desired level of security. Such twinning must, of course, be compared with the single line which not only incurs the repair cost but also loss of gas production during shutdown for repair. The twin line will not however totally eliminate loss of production should one of the lines be damaged since isolation of the damaged line will incur delays.

The above extremely approximate analysis serves to indicate the need to establish the "real" level of risk since the twinning cost may be equivalent to a relatively high number of repairs.

9.3.5 Over-Sized Pipelines

Section 7.8.2 discussed increased line sizes given the same operating conditions used to size the line for 250 MMSCFD. The peak throughput of the 330 mile, 24" line adopted is 430 MMSCFD of "dense phase" gas. Increased line sizes capable of handling up to twice the quantity are as follows:

Line Size	Peak Throughput (MMSCFD)
24"	430 (1.00)
28"	650 (1.51)
30"	780 (1.81)
32"	930 (2.16)

Data in parenthesis are the multipliers of peak throughput compared to the 24" line size.

In approximate terms, it is estimated that the gas transmission system, including the submarine line, landline and the gas reception facilities, will incur the following increases in cost to achieve the above increases in throughput:

Line Size	Cost Increase on 24" Line
28"	15% to 20%
30"	25% to 30%
32"	35% to 40%

There is advantage therefore in installing an over-size pipeline, if the probability of increased throughput is high, since the cost multiplier is significantly less than the throughput multiplier.

Investment analysis is required however to determine whether it is better to install an over-size line or to twin the line later in the project life as required. This is particularly true for the onshore landline and gas reception facilities where an incremental approach to increasing throughput is more readily adopted. The option of adding intermediate compression to the system at a later date, say at the landfall, should also be considered.

9.4 CAPITAL EXPENDITURE PHASING - INCLUDING SOUTHERN PIPELINE ROUTE

The capital expenditure phasing schedules for:

i) Offshore Structures and Facilities
ii) Submarine Gas Pipeline (260 miles)
iii) Onshore Gas Landline (70 miles)
iv) Gas Reception Facilities

are given in Table 9-7 through Table 9-10.

These investment schedules relate to the Project Phase of the development only, the Conceptual Field Development Schedule presented in Section 8.0 and the Capital Cost Assessment for each area presented in Section 9.2.

The indicated phasing is on a gross expenditure basis and does not account for invoicing lag or accruals. The costs are base costs as of 1st January, 1982 and should be inflated as required for economic evaluations.

Pre-project and development drilling costs are not included in the schedules, and no account is taken of the influence of inflation.

At this time, the expenditure phasing should be regarded as preliminary and indicative only, particularly with regard to gross allowances for management, etc., and contingencies. It may be noted that construction of the gas landline and gas reception facilities may be delayed by one year if desired.

It is emphasized that the schedules relate only to the development concept adopted for Study purposes and that a different engineering approach may significantly alter the schedules both in absolute and relative terms. Further, detailed technical definition and planning may alter the schedules, e.g., should reduction in overall schedule length be required.

TABLE 9-7 OFFSHORE STRUCTURES AND FACILITIES - PROJECT CAPITAL EXPENDITURE PHASING

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

OFFSHORE STRUCTURES AND FACILITIES	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. STRUCTURES/FACILITIES SUPPLY									
A. Semi-Submersible Support Structures	600.00	-	100.00	200.00	200.00	100.00	-	-	-
B. Topside Facilities	297.58	-	25.00	80.00	100.00	70.00	22.58	-	-
C. Oil Storage/Export Systems	350.00	-	-	-	175.00	175.00	-	-	-
D. Riser Manifold Bases	60.00	-	10.00	30.00	20.00	-	-	-	-
E. Risers/Riser Handling Systems	65.00	-	-	10.00	35.00	20.00	-	-	-
F. Cluster Manifold Centres	84.00	-	10.00	27.00	27.00	20.00	-	-	-
G. Subsea Control Systems	48.00	-	-	5.00	20.00	20.00	3.00	-	-
H. Wellhead/Completion Equipment	304.00	-	9.00	35.00	60.00	100.00	75.00	25.00	-
I. OMC Flowline Bundles	36.00	-	-	18.00	18.00	-	-	-	-
J. In-Field Transfer Lines	8.05	-	-	-	4.00	4.05	-	-	-
K. Satellite Flowline Bundles	30.00	-	-	-	-	10.00	10.00	10.00	-
L. FPP Anchor Piles	0.72	-	-	0.36	0.36	-	-	-	-
M. OMC/Riser Base Piles	0.60	-	-	0.25	0.10	0.25	-	-	-
SUB-TOTAL	1,883.95	-	154.00	405.61	659.46	519.30	110.58	35.00	-
2. OFFSHORE CONSTRUCTION/INSTALLATION									
A. General Allowances	343.68	-	-	33.68	90.00	110.00	100.00	10.00	-
B. Seabed Excavations	287.95	-	30.00	90.00	90.00	60.00	17.95	-	-
C. OMC/Riser Manifold Bases	28.00	-	-	5.60	11.20	5.60	5.60	-	-
D. FPP Anchor Piles	9.60	-	-	1.20	4.80	3.60	-	-	-
E. Flowline Bundles	12.92	-	-	-	2.75	2.12	4.35	1.85	1.85
F. In-Field Transfer Lines	19.25	-	-	-	6.25	6.50	6.50	-	-
G. Oil Storage/Export Systems	54.60	-	-	-	-	14.60	40.00	-	-
H. Floating Production Platforms	2.28	-	-	-	-	1.14	1.14	-	-
SUB-TOTAL	758.28	-	30.00	130.48	205.00	203.56	175.54	11.85	1.85

... continued

TABLE 9-7 OFFSHORE STRUCTURES AND FACILITIES - PROJECT CAPITAL EXPENDITURE PHASING

(Continued)

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

OFFSHORE STRUCTURES AND FACILITIES	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
3. MANAGEMENT, ETC.									
A. Mgt., Supervision, Design, Eng.	317.07	30.00	50.00	50.00	80.00	80.00	25.00	2.07	-
B. Commissioning/Start-up	132.11	-	-	-	2.11	35.00	65.00	30.00	-
C. Insurance	79.27	-	5.52	16.08	25.93	21.69	8.58	1.41	0.06
SUB-TOTAL	528.45	30.00	55.52	66.08	108.04	136.69	98.58	33.48	0.06
OFFSHORE STRUCTURES AND FACILITIES BASE COST	3,170.68	30.00	239.52	602.17	972.50	859.55	384.70	80.33	1.91
4. CONTINGENCY	951.20	9.00	71.86	180.65	291.75	257.86	115.41	24.10	0.57
OFFSHORE STRUCTURES AND FACILITIES PROJECT BUDGET	4,121.88	39.00	311.38	782.82	1,264.25	1,117.41	500.11	104.43	2.48

Notes: 1. Project Budget Excludes Pre-Project Costs And Development Drilling Costs.

2. All Costs Are Base 1.1.1982 with No Allowance For The Effects Of Inflation.

TABLE 9-8 SUBMARINE GAS PIPELINE - HIBERNIA TO TREPASSEY BAY

PROJECT CAPITAL EXPENDITURE PHASING

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

SUBMARINE GAS PIPELINE (260 Miles)	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. MATERIALS	204.78	-	50.00	144.78	10.00	-	-	-	-
2. CONSTRUCTION									
A. Pre-Laying Activities	41.61	3.60	18.40	14.80	4.81	-	-	-	-
B. Landfall	30.00	-	5.00	15.00	5.00	5.00	-	-	-
C. Pipelaying/Pipe Supply	129.12	-	-	30.00	80.00	19.12	-	-	-
D. Trenching	97.00	-	-	17.50	60.00	19.50	-	-	-
E. Post-Lay Activities	49.70	-	-	-	-	15.00	34.70	-	-
F. Tie-ins	2.25	-	-	-	-	-	2.25	-	-
SUB-TOTAL	349.68	3.60	23.40	77.30	149.81	58.62	36.95	-	-
3. MANAGEMENT, ETC.									
A. Mgt., Supervision, Design, Eng.	33.27	2.00	5.00	5.00	10.00	5.00	5.00	1.27	-
B. Test/Commissioning/Start-up	13.86	-	-	-	-	-	3.86	10.00	-
C. Insurance	16.63	0.11	2.20	6.66	4.79	1.76	1.11	-	-
SUB-TOTAL	63.76	2.11	7.20	11.66	14.79	6.76	9.97	11.27	-
BASE COST	616.22	5.71	80.60	233.74	174.60	65.38	46.92	11.27	-
4. CONTINGENCY	123.64	1.14	16.12	46.75	34.92	13.08	9.38	2.25	-
PROJECT BUDGET	741.86	6.85	96.72	280.49	209.52	78.46	56.30	13.52	-

Notes: 1. Project Budget Excludes Pre-Project Costs.

2. All Costs Are Based 1.1.1982 With No Allowance For The Effects Of Inflation.

TABLE 9-9 ONSHORE GAS LANDLINE - TREPASSEY BAY TO LONG HARBOUR

PROJECT CAPITAL EXPENDITURE PHASING

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

ONSHORE GAS LANDLINE (70 Miles)	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. MATERIALS	50.09	-	-	50.09	-	-	-	-	-
2. CONSTRUCTION									
A. Route Preparation	24.59	-	-	8.00	16.59	-	-	-	-
B. Pipelaying	61.77	-	-	-	20.00	41.77	-	-	-
SUB-TOTAL	86.36	-	-	8.00	36.59	41.77	-	-	-
3. MANAGEMENT, ETC.									
A. Mgt., Supervision, Design, Eng.	8.19	0.60	2.00	0.50	2.50	2.50	-	0.09	-
B. Test/Commissioning/Start-up	3.41	-	-	-	-	3.00	-	0.41	-
C. Insurance	2.73	-	-	1.16	0.73	0.84	-	-	-
SUB-TOTAL	14.33	0.60	2.00	1.66	3.23	6.34	-	0.50	-
LANDLINE BASE COST	150.78	0.60	2.00	59.75	39.82	48.11	-	0.50	-
4. CONTINGENCY	15.08	0.06	0.20	5.98	3.98	4.81	-	0.05	-
LANDLINE PROJECT BUDGET	165.86	0.66	2.20	65.73	43.80	52.92	-	0.55	-

Notes:
1. Project Budget Excludes Pre-Project Costs.
2. All Costs Are Base 1.1.82 With No Allowance For The Effects Of Inflation.
3. Construction Of The Landline May Be Delayed By One Year If Desired.

TABLE 9-10 ONSHORE GAS RECEPTION FACILITIES - PROJECT CAPITAL EXPENDITURE PHASING

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

ONSHORE GAS RECEPTION FACILITIES	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. SUPPLY/CONSTRUCTION INSTALLATION	20.00	-	-	1.00	14.00	5.00	-	-	-
2. MANAGEMENT, ETC.									
A. Mgt., Supervision, Design, Eng.	2.40	-	-	0.50	1.20	0.50	-	0.20	-
B. Commissioning/Start-up	1.00	-	-	-	-	0.10	-	0.90	-
C. Insurance	0.40	-	-	0.02	0.28	0.10	-	-	-
SUB-TOTAL	3.80	-	-	0.52	1.48	0.70	-	1.10	-
GAS RECEPTION FACILITIES BASE COST	23.80	-	-	1.52	15.48	5.70	-	1.10	-
3. CONTINGENCY	4.76	-	-	0.30	3.10	1.14	-	0.22	-
GAS RECEPTION FACILITIES PROJECT BUDGET	28.56	-	-	1.82	18.58	6.84	-	1.32	-

Notes:
1. Project Budget Excludes Pre-Project Costs.
2. All Costs Are Base 1.1.82 With No Allowance For The Effects Of Inflation.
3. Construction Of The Gas Reception Facilities May Be Delayed By One Year If Desired.

9.5 DIRECT PIPELINE ROUTE VIA BAY BULLS

9.5.1 Basis for Cost Assessment

The same basis for cost assessment defined in Section 9.1 for the southern line has been adopted for the northern pipeline with the exceptions that for the landline:

i) Route characteristics, e.g., rock grading, have been pro-rated from 70 miles to 55 miles; and
ii) 25 Creek/River Crossings and 5 Road/Railway Crossings are assumed.

Since the line sizes are the same for both routes, i.e., 24", no other variations arise.

9.5.2 Overall Project Costs

For a Hibernia Field Development including a 250 mile gas pipeline to Long Harbour via a Bay Bulls landfall, the component costs for the Offshore Structures and Facilities, and the Onshore Gas Reception Facilities remain as for the southern route via Trepassey Bay. Although the line diameter adopted is similar, 24", the pipeline project budget decreases due to the reduced line length (250 miles for the northern route compared to 330 miles for the southern route). This reduction is offset by an increase in the cost allowance for seabed rock grading and in protection of exposed pipeline, although trenching remedial work is reduced.

A summary of the overall Project Budget, which results from brief consideration of costs for the northern route for the Hibernia development, including a 250 mile, 24" pipeline via Bay Bulls, is given in Table 9-11.

The Project Budget excludes pre-project costs and development drilling and indicates a capital cost in the order of $4.88 Billion including contingencies of approximately 28% of the Base Project Cost.

TABLE 9-11 OVERALL PROJECT BUDGET SUMMARY

HIBERNIA FIELD DEVELOPMENT

OVERALL PROJECT BUDGET SUMMARY
(Including 250 Mile Pipeline Via Bay Bulls)

	Cost, $MM 1.1.82
1. BASE COST	
A. Offshore Structures and Facilities	
i) Structures/Facilities Supply	1,883.95
ii) Offshore Construction/Installation	758.28
Offshore Structures and Facilities Sub-Total	2,642.23
B. Submarine Gas Pipeline (195 mile)	
i) Materials	153.58
ii) Construction	294.03
Submarine Gas Pipeline Sub-Total	447.61
C. Onshore Gas Landline (55 mile)	
i) Materials	39.35
ii) Construction	64.66
Onshore Gas Landline Sub-Total	104.01
D. Onshore Gas Reception Facilities	20.00
Base Cost Excluding Management, Engineering, Commissioning, Insurance	3,213.85

Cont'd/ ...

TABLE 9-11 OVERALL PROJECT BUDGET SUMMARY (Cont'd.)

E.	Management, Engineering, Commissioning, Insurance	
i)	Offshore Structures and Facilities	528.45
ii)	Submarine Gas Pipeline	51.48
iii)	Onshore Gas Landline	10.92
iv)	Gas Reception Facilities	3.80
	Management, Engineering, Commissioning, Insurance Sub-Total	594.65
	Project Base Cost	3,808.50

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2. CONTINGENCY

A.	Offshore Structures and Facilities	951.20
B.	Submarine Gas Pipeline	99.82
C.	Onshore Gas Landline	11.49
D.	Onshore Gas Reception Facilities	4.76
	Contingency Sub-Total	1,067.27
	Total Project Budget	4,875.77

Notes:
1. Project Budget Excludes Pre-Project And Development Drilling.
2. Submarine Pipeline Trenching Costs Included Are For Conventional Burial By Jetting Only.
3. All Costs Are 1.1.1982 With No Allowance For The Effects Of Inflation.

Including pre-project and development drilling costs as defined in Section 9.2.1 (ie. $400 MM to $500 MM and $2,000 MM respectively) the total Field Development Budget for Hibernia would be in the order of $7.33 Billion in 1.1.1982 terms.

All items of general discussion given in Section 9.1 for the southern route apply equally to the northern route.

The individual Project Budget assessments for the 195 mile Submarine Gas Pipeline an the Onshore Gas Landline are given in Tables 9-12 and 9-13 respectively, the Project Budgets for all four main areas of the development being summarised as follows:

Area	Project Budget $MM 1.1.82
Offshore Structures and Facilities	4,121.88 (309.14)
Submarine Gas Pipeline (195 miles)	598.91 (29.95)
Onshore Gas Landline (55 miles)	126.42 (1.26)
Onshore Gas Reception Facilities	28.56 (0.86)
TOTAL	4,875.77 (341.21)

The operating costs in the peak year of production are given in parenthesis above.

TABLE 9-12 SUBMARINE GAS PIPELINE - CAPITAL COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

SUBMARINE GAS PIPELINE PROJECT BUDGET - HIBERNIA TO BAY BULLS

		ITEM	Cost, $MM 1.1.82
1.	Materials		153.58
2.	Construction		
	A.	Pre-Laying Activities	46.41
	B.	Landfall	30.00
	C.	Pipelaying/Pipe Supply (195 miles)	104.42
	D.	Trenching (Refer to Note 1)	47.50
	E.	Post-Lay Activities	63.45
	F.	Tie-ins	2.25
		Construction Sub-Total	294.03
3.	Management, etc.		
	A.	Mgt., Supervision, Design, Eng. (6%)	26.86
	B.	Test/Commissioning/Start-up (2-1/2%)	11.19
	C.	Insurance (3%)	13.43
		Management, etc. Sub-Total	51.48
		Base Cost	499.09
4.	Contingency (20%)		99.82
		Project Budget	598.91

Notes:

1. Indicative Allowance For Trenching Is For Conventional Offshore Trenching To, Typically, 3 Ft. Cover Over 50% (97.5 miles) Of The 195 Mile Pipeline. No Allowance Is Made For Deep Burial Over This Length, Or For Burial In Rock Zones In The Avalon Channel Beyond The Landfall.
2. Project Budget Excludes Pre-Project Costs.
3. All Costs Are Base 1.1.1982 With No Allowance For The Effects Of Inflation.

TABLE 9-13 ONSHORE GAS LANDLINE - CAPITAL COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

ONSHORE GAS LANDLINE PROJECT BUDGET - BAY BULLS TO LONG HARBOUR

	ITEM		Cost, $MM 1.1.82
1.	Materials		39.35
2.	Construction (55 miles)		
	A.	Route Preparation	19.39
	B.	Pipelaying	45.27
		Construction Sub-Total	64.66
3.	Management, etc.		
	A.	Mgt., Supervision, Design, Eng. (6%)	6.24
	B.	Test/Commissioning, Start-up (2-1/2%)	2.60
	C.	Insurance (2%)	2.08
		Management, etc. Sub-Total	10.92
		Base Cost	114.93
4.	Contingency (10%)		11.49
		Project Budget	126.42

Notes:
1. Project Budget Excludes Pre-Project Costs.
2. All Costs Are Base 1.1.1982 With No Allowance For The Effects Of Inflation.

9.5.3 Gas Transmission System Costs

The capital and peak year operating costs of the gas transmission system, via a Bay Bulls landfall downstream of the Riser Manifold Base at Hibernia South are as follows (given the same operating cost basis as for the southern route):

Area	CAPEX, $MM 1.1.82	OPEX $MM P.A. 1.1.82
Submarine Gas Pipeline (195 miles)	598.91	29.95
Onshore Gas Landline (55 miles)	126.42	1.26
Onshore Gas Reception Facilities	28.56	0.86
	753.89	32.07

The Associated Offshore Equipment Costs will be as per the southern system (refer Section 9.3.2). Table 9-14 presents a summary of overall gas transmission system costs including associated equipment.

With respect to the costs of major repair, multiple pipelines and oversize pipelines, the northern route will be similar to the southern route with the exception that the basic installed cost per mile of the 195 mile, 24" line is in the order of $2.5 MM per mile (derived from Appendix III). The total cost to install a twinned line over any particular distance "L" miles of submarine line is therefore in the order of $(3L x 2.5 + 60) MM.

With reference to the capital cost breakdown given in Appendix III, it should be noted that no penalties for minimum charter periods for the laybarge and the trench barge are applied. However, for the northern route, only one trench barge mobilisation cost is allocated to the main submarine gas pipeline, compared to two for the longer southern route, but a further mobilisation cost is allocated to trench remedial work. Thus the trench barge mobilisation costs are the same for both routes but are allocated differently.

TABLE 9-14 SUMMARY OF OVERALL GAS TRANSMISSION SYSTEM COST ASSESSMENT

HIBERNIA FIELD DEVELOPMENT

GAS TRANSMISSION SYSTEM PROJECT BUDGET - BAY BULLS LANDFALL

		Cost Summary, $MM, 1.1.82	
	ITEM	Project Budget	Peak Year OPEX
1.	Offshore FPP Associated Equipment		
	A. Topsides Facilities	6.16	0.46
	B. Riser Systems	4.50	0.34
	C. Riser Manifold Base	1.80	0.14
	Offshore FPP Associated Equipment Sub-Total	12.46	0.94
2.	Submarine Gas Pipeline (195 miles)	598.91	29.95
3.	Onshore Gas Landline (55 miles)	126.42	1.26
4.	Onshore Gas Reception Facilities	28.56	0.86
	Overall Gas Transmission System	766.35	33.01

Notes:
1. Project Budget Excludes Pre-Project And Development Drilling.
2. Submarine Pipeline Trenching Costs Included Are For Conventional Burial by Jetting Only.
3. All Costs Are 1.1.82 With No Allowance For The Effects Of Inflation.

9.5.4 Capital Expenditure Phasing

The capital expenditure phasing schedules for the Submarine Gas Pipeline and the Onshore Gas Landline relating to the northern pipeline route via Bay bulls are given in Tables 9-15 and 9-16.

These schedules relate to the project phase of the development schedule presented generally in Section 8.0, specifically modified for the northern route in Section 8.4, and the Capital Cost Assessment for the two areas presented in Section 9.5.1.

All discussion presented in Section 9.4 for the southern route applies equally to the northern route.

9.5.5 Reduced Line Size

For information, if a 22" O.D. pipeline were to be recommended for the northern route (as discussed in Section 7.9.2) and if no premiums were to be applied to the supply and construction of this non-standard line size, then significant material cost savings may be realised compared to the 24" line, laying costs being marginally reduced. In general terms the overall saving may be in the order of $40 MM but the negotiable elimination of premiums, and the availability of suitable equipment to construct a 22" pipeline, must be carefully reviewed prior to the recommendation of such a non-standard size.

TABLE 9-15 SUBMARINE GAS PIPELINE - HIBERNIA TO BAY BULLS

PROJECT CAPITAL EXPENDITURE PHASING

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

SUBMARINE GAS PIPELINE (195 Miles)	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. MATERIALS	153.58	-	35.00	113.58	5.00	-	-	-	-
2. CONSTRUCTION									
A. Pre-Laying Activities	46.41	2.80	21.10	17.00	5.51	-	-	-	-
B. Landfall	30.00	-	5.00	15.00	5.00	5.00	-	-	-
C. Pipelaying/Pipe Supply	104.42	-	-	30.00	74.42	-	-	-	-
D. Trenching	47.50	-	-	-	25.00	22.50	-	-	-
E. Post-Lay Activities	63.45	-	-	-	10.00	51.05	2.40	-	-
F. Tie-ins	2.25	-	-	-	-	-	2.25	-	-
SUB-TOTAL	294.03	2.80	26.10	62.00	119.93	78.55	4.65	-	-
3. MANAGEMENT, ETC.									
A. Mgt., Supervision, Design, Eng.	26.86	2.00	4.00	4.00	8.00	7.00	0.86	1.00	-
B. Test/Commissioning/Start-up	11.19	-	-	-	-	-	2.19	9.00	-
C. Insurance	13.43	0.08	1.83	5.27	3.75	2.36	0.14	-	-
SUB-TOTAL	51.48	2.08	5.83	9.27	11.75	9.36	3.19	10.00	-
BASE COST	499.09	4.88	66.93	184.85	136.68	87.91	7.84	10.00	-
4. CONTINGENCY	99.82	0.98	13.39	36.96	27.34	17.58	1.57	2.00	-
PROJECT BUDGET	598.91	5.86	80.32	221.81	164.02	105.49	9.41	12.00	-

Notes: 1. Project Budget Excludes Pre-Project Costs.

2. All Costs Are Based 1.1.1982 With No Allowance For The Effects Of Inflation.

TABLE 9-16 ONSHORE GAS LANDLINE - BAY BULLS TO LONG HARBOUR

PROJECT CAPITAL EXPENDITURE PHASING

HIBERNIA FIELD DEVELOPMENT

ALL COSTS $MM (1.1.82)

ONSHORE GAS LANDLINE (55 Miles)	TOTAL	YEAR 1	YEAR 2	YEAR 3	YEAR 4	YEAR 5	YEAR 6	YEAR 7	YEAR 8
1. MATERIALS	39.35	-	-	39.35	-	-	-	-	-
2. CONSTRUCTION									
A. Route Preparation	19.39	-	-	6.00	13.39	-	-	-	-
B. Pipelaying	45.27	-	-	-	15.00	30.27	-	-	-
SUB-TOTAL	64.66	-	-	6.00	28.39	30.27	-	-	-
3. MANAGEMENT, ETC.									
A. Mgt., Supervision, Design, Eng.	6.24	0.46	1.52	0.38	1.90	1.90	-	0.08	-
B. Test/Commissioning/Start-up	2.60	-	-	-	-	2.30	-	0.30	-
C. Insurance	2.08	-	-	0.91	0.57	0.60	-	-	-
SUB-TOTAL	10.92	0.46	1.52	1.29	2.47	4.80	-	0.38	-
LANDLINE BASE COST	114.93	0.46	1.52	46.64	30.86	35.07	-	0.38	-
4. CONTINGENCY	11.49	0.05	0.15	4.65	3.09	3.51	-	0.04	-
LANDLINE PROJECT BUDGET	126.42	0.51	1.67	51.29	33.95	38.58	-	0.42	-

Notes: 1. Project Budget Excludes Pre-Project Costs.

2. All Costs Are Base 1.1.82 With No Allowance For The Effects Of Inflation.

3. Construction Of The Landline May Be Delayed By One Year If Desired.

9.6 CRITICAL AREAS OF THE COST ASSESSMENT

The capital and operating cost assessment made for Study purposes relates only to the development concept and schedule adopted for Study purposes. Any variation in either of these items will require a review of the assessment.

The assessment is based on a 1.1.82 datum but considerable variations can arise in short term rates for services depending on market forces and also on the lead time available to negotiate contracts. A detailed check has not been made on current contractor rates; rather, costs have been factored from other recent developments world-wide, particularly the North Sea, an area which is considered to offer a reasonable degree of comparability with Atlantic Canada. The cost assessment made is therefore order-of-magnitude only and reasonably conservative. A relatively high level of contingency has been included for lack of project definition at this time.

The contingency has been applied as a percentage allowance on the base cost of each key area. At a more detailed level of assessment contingencies would be associated with each individual item of the cost estimate to reflect the relative confidence in the assessment of each item and its susceptibility to variation as a result of lack of technical definition, delays, etc. This level of detail is not available at this time however and thus the overall percentage allowance method has been adopted. It should also be noted that no allowance has been made for the lack of definition of reservoir and field production data.

Further, at this level of assessment, design, engineering and management costs, etc., have been allowed for on a percentage basis. Detailed estimation would be based on manhour content for such items and may lead to reductions in the overall cost of these items.

The cost levels used will also be significantly influenced by the long term variation in basic costs, e.g., materials and labour, as well as by the source of supply and location of construction sites. In general, typical international supply costs have been used with no consideration of the influence of maximizing Newfoundland or Canadian content. However, assuming market forces apply, contract value may not alter considerably with increased Newfoundland or Canadian content (this is not to say the real cost for Canadian content may not be higher). However, where little or no experience is available in the supply or construction of equipment or facilities, an increase in indirect costs may arise due to learning curve aspects, delays, etc. No allowance is made for this for Study purposes.

No allowance has been made for sales tax on the supply of materials or equipment, the application of which may have a considerable effect on final costs. Further, no allowance has been made for the effect of inflation over project life.

With respect to the offshore installation, the assumed inclusion of seabed excavation adds a considerable cost to the development (as well as critically controlling the project schedule). The magnitude of this cost suggests that alternative methods of iceberg scour protection should receive detailed consideration.

With regard to the submarine gas pipeline, the allowance for trenching is nominal. Detailed soils investigation to determine the applicability of conventional trenching may considerably increase this cost component, as would a requirement for additional protection for exposed pipe in rocky seabed areas.

The overall cost of the landline is high due to the assumed extensive amount of rock grading, ditching, creek/river crossings required. The cost per inch-mile is not however out-of-line with similar projects elsewhere in Canada. Detailed route survey may considerably modify the assessment made in this Study.

With respect to the gas reception facilities, the cost assessment is considered a minimum due to the few facilities required. The inclusion of any gas separation/processing facilities would increase the assessment considerably.

In overall terms, the assessment indicates that the Hibernia Field will be a high capital cost project and that a gas transmission system will be a significant addition to facilities installed for the production of oil alone. A detailed economic analysis of the total development is therefore required to justify the export of gas, subject to the acceptability of the iceberg scour risk.

The adoption of a northern pipeline route, e.g., via a BayBulls landfall, offers the benefit of a significant reduction in cost, compared to a longer southern route, e.g., via a Trepassey Bay landfall. The magnitude of this benefit is dependent on detailed route survey data, detailed engineering and the establishment of the relative risk pipeline damage between alternative routes.

If the Avalon and Hibernia reservoirs are developed separately, on an incremental basis, then the estimated capital cost presented in this Study would have to be completely re-assessed.

APPENDICES

I. DATA AND INFORMATION AVAILABLE TO THE STUDY

II. CAPITAL COST BREAKDOWN - OVERALL PROJECT INCLUDING SOUTHERN PIPELINE VIA TREPASSEY BAY LANDFALL

III. CAPITAL COST BREAKDOWN - NORTHERN PIPELINE VIA BAY BULLS LANDFALL

APPENDIX I

DATA AND INFORMATION AVAILABLE TO THE STUDY

THIS APPENDIX LISTS THE DATA AND INFORMATION MADE AVAILABLE TO THE STUDY BY THE GOVERNMENT OF NEWFOUNDLAND AND LABRADOR, PETROLEUM DIRECTORATE AND UPON WHICH THE PRELIMINARY INVESTIGATION HAS BEEN BASED.

APPENDIX I - DATA AND INFORMATION AVAILABLE TO THE STUDY

Item No.	Item Description	Date Received
J31-1/7575/1	Bathymetry Chart	7/12/81
/2	100 year Design Parameters, (Note by C.J. Noll, Ocean Engineer, Pet. Dir.)	7/12/81
/3	Hibernia Development Environmental Criteria, (Abstract from Pet. Dir. Hibernia Symposium)	7/12/81
/4	Mobil Oil Canada, "Physical and Environmental Considerations", Mobil et al., Oct. 1981, (Hibernia J-34 Submission - Odeco Ocean Ranger), Abstract, Section 8 - Environmental Data	7/12/81
/5	Mobil, "Supporting Environmental Information Manual", (GB Oil Spill Contingency Plan, Unit 2), Abstract, "Physical Environment Summary"	7/12/81
/6	"A Preliminary Physical and Biological Environmental Baseline Study and Environmental Impact Analysis of Blowouts for the Shelf Zone of South Eastern and Southern Newfoundland Waters", Nordco & Northland, April 7, 1978	7/12/81
	6.1 Appendix 1-25, Physical Environment Data	7/12/81
	6.2 Section 3, Physical Environment	7/12/81
/7	Fader, G.B. and King, L.H., "A Reconnaissance Study of the Surficial Geology of the Grand Banks of Newfoundland", in Current Research, Part A, Geological Survey of Canada, Paper 81-1A, pp 45-56, 1981	7/12/81
/8	Bedrock Geology Chart (Tertiary & Older) (2 copies)	7/12/81

Item No.	Item Description	Date Received
J31-1/7575/9	Newfoundland Government Hibernia Study, "Conceptual Facilities Design", by INTERCOMP	7/12/81
	9.1 Draft Copy Report (edited by NLPD) 9.2 Equipment List for Principal Items 9.3 Process Flow Scheme	
/10	Hibernia Proposed Development Plan, Well, FPF and Flowline Locations, (Case 4), INTERCOMP	7/12/81
/11	Hibernia Field PVT Data, (INTERCOMP)	7/12/81
	11.1 Avalon Reservoir 11.2 Hibernia Reservoir B-08 Block 11.3 Hibernia Reservoir B-15 Block	
/12	Hibernia Field Gas Production, Combined Streams	7/12/81
/13	Injection Gas Composition, Combined Streams	7/12/81
/14	Well Locations Chart, (Hibernia/Hebron/Ben Nevis/ South Tempest/Nautilus)	7/12/81
/15	Wave Data from P-35 Submission, (by Telex)	15/12/81
/16	Gas Stream Data (by Telex), Table 1: DST Gas Table 2: Avalon & Hibernia Compressor Outlet Gas	17/12/81
/17	O-35 Well, Downhole Sample Analysis (by Telecopier), Flowing Temp/Press/Rate	17/12/81
/18	B-08 Data, similar /17	13/1/82
/19	P-15 Data, similar /17	13/1/82
/20	Production Profiles (for information on Water), Avalon & Hibernia INTERCOMP Data, Most Likely Reserves - Medium Rates Avalon/High Rates Hibernia	13/1/82

Item No.	Item Description	Date Received
J31-1/7575/21	Hydrocarbon Liquid Analysis - Recombined Fluid, 0-35	13/1/82
/22	Gas & Hydrocarbon Liquid Analysis at Each Stage of DST Separation Train, 0-35	13/1/82
/23	Supporting Environmental Information Manual - Mobil Oil Canada Ltd., Grand Banks Oil Spill Contingencies Plan, Unit 2, April 1980	28/1/82

OTHER REFERENCES

1. A Climatalogic Study of the Southern Davis Strait, for Esso Resources Canada by Nordco (extends to South Newfoundland).

2. On Predicting Iceberg Drift, D.G. Mountain, U.S. Coastguard Oceanographic Unit, Washington, D.C.
"Cold Regions Science and Technology, 1 (1980) 273-282.

3. Guidelines for the Approval of a Hibernia Development Program, Submitted to Mobil Oil Canada Ltd., July 1981, by Petroleum Directorate Government of Newfoundland and Labrador.

APPENDIX II

CAPITAL COST BREAKDOWN - OVERALL PROJECT INCLUDING SOUTHERN PIPELINE VIA TREPASSEY BAY LANDFALL

II.1 OFFSHORE STRUCTURES AND FACILITIES........................... 1
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APPENDIX II - CAPITAL COST BREAKDOWN - OVERALL PROJECT

INCLUDING SOUTHERN PIPELINE VIA TREPASSEY BAY LANDFALL

II.1 OFFSHORE STRUCTURES AND FACILITIES

	Cost, $MM 1.1.82
II.1.1 Semi-Submersible Support Structures (4 No.)	
To Supply Large, Severe Environment, Semi-Submersible Complete Including:	
* Hull	
* Hull Systems and Outfit	
* Marine and General Equipment	
4 No. @ $150 MM each	600.00
II.1.2 Topsides Facilities	
To Supply and Install at Dockside, Total Topside Production, Utilities, Life Support Systems, etc.	
A. Avalon North: 50,000 BOPD; 20 MMSCFD; 150,000 BWPD	
Materials and Equipment	51.03
Installation	17.83
Sub-Total A	68.86
B. Avalon South: 90,000 BOPD; 30 MMSCFD; 150,000 BWPD	
Materials and Equipment	53.05
Installation	19.53
Sub-Total B	72.58

	Cost, $MM
	1.1.82
C. Hibernia North: 50,000 BOPD; 100 MMSCFD	
Materials and Equipment	48.75
Installation	17.08
Sub-Total C	65.83
D. Hibernia South: 90,000 BOPD, 100 MMSCFD 250 MMSCFD Inj./Export	
Materials and Equipment	58.11
Installation	21.65
Sub-Total D	79.76
E. Misc. Operating Spares - Commissioning - Pre-production Phase Materials/Equipment 5% Materials and Equipment	10.55
Sub-Total II.1.2	297.58

II.1.3 Oil Storage/Mooring/Loading System

Assumed Based on Converted Tanker; 250,000 ton dwt Providing 1 MM barrels; Assume 2 No. Required (7 days Storage)

A. Storage Tanker Purchase/Conversion Including Over-Stern Shuttle Tanker Mooring/Loading System 2 No. @ $75 MM each	150.00

	Cost, $MM 1.1.82
B. Storage Tanker Mooring/Riser System SALM/Yoke Mooring Assumed 2 No. @ $50 MM each	100.00
C. Shuttle Tanker Remote Mooring/Loading Terminal SALM/ALT Assumed 2 No. @ $50 MM each	100.00
Sub-Total II.1.3	350.00

II.1.4 Riser Bases

To Supply 4 No. Riser Bases Including: Templates; Manifold Valves; Piping, Chokes, Mandrels; TFL Selectors/Loops; Flowline/Transfer Line Connections/Pull-in Sleds/Loops; Pig/Sphere Launcher System 4 No. @ $15 MM each	60.00

II.1.5 Risers/Riser Handling Systems

A. To Supply 4 No. + 2 Spare Integral Production Risers Each Including Riser Joints; Riser Connections; Riser Head and Bottom Connection 6 No. @ $7.5 MM each	45.00

	Cost, $MM 1.1.82
B. To Supply 4 No. Riser Handling/Tensioning Systems	
4 No. @ $5 MM each	20.00
Sub-Total II.1.5	65.00

II.1.6 Cluster Manifold Centres

To Supply 6 No. 12-Slot CMC's, Including: Manifold Valves and Piping; TFL Selectors/Loops, Flowline Connections/Pull-in Sleds/Loops	
6 No. @ $14 MM each	84.00

II.1.7 Control System

To Supply 4 No. Control Systems, Including: Electrohydraulics, Acoustic Back-up Surface Control/Power Package; Hyd/Elec. Jumpers and Storage Reels; Cable Tensioning System; Each to Service 2 CMC/1 Riser Base/4 Satellite Wells	
4 No. @ $12 MM each	48.00

		Cost, $MM 1.1.82
II.1.8	Wellhead/Completion Equipment (Excluding Tubulars/Downhole Equipment)	
	A. To Supply 4 Sets Each Comprising: * 2 No. Completion/Workover Risers * 1 No. Wireline BOP Unit 4 No. @ $5.5 MM each set	22.00
	B. To Supply 6 No. Sets of CMC Wellhead/ Completion Equipment For 12 Wells Including Trees, Caps, Tubing Hangers, Running Tools, Chokes and Valves 6 No. @ $35 MM each set of 12	210.00
	C. To Supply 16 No. Satellite Well Templates and Wellhead Equipment Including Flowline Pull-In Sleds 16 No. @ $4.5 MM	72.00
	Sub-Total II.1.8	304.00
II.1.9	CMC To Riser Base Flowline Bundles	
	To Supply 6 Sets of 2 No. x 5,000 ft. Bundled Flowlines/Control Lines in 24" Carrier Pipe Fabricated and Assembled Including: Pipe Handling; Storage; Concrete Coating; Buoyancy/ Chains For Off-Bottom Tow 6 x 2 No. @ $3 MM each	36.00

	Cost, $MM 1.1.82
II.1.10 In-Field Transfer Lines	
A. To Supply Approximately 35 Miles + 10% of Pipe; Diameters Ranging Between 8" to 24"; Assume 5,000 tons @ $1,000/ton	5.00
B. Anodes, Coat @ $10 ft. (Includes Some Concrete Coating)	2.03
C. Pipe Handling/Storage @ $5/ft.	1.02
Sub-Total II.1.10	8.05
II.1.11 Satellite Well Flowline Bundles	
To Supply 20 No. (16 + 4 Spare) 5,000 ft. Bundled Flowline/Control Lines in 10" Carrier Pipe 20 No. @ $1.5 MM each	30.00
II.1.12 Anchor Piles	
A. Semi-Submersible FPP, To Supply 4 Sets of 12 No. 36", 60 ft. Anchor Piles at $15,000 Each Including Mooring Line Connectors	0.72

	Cost, $MM 1.1.82
B. CMC/Riser Base Piles To Supply 10 Sets of 6 No. 30", 60' Anchor Piles at $10,000 each	0.60
Sub-Total II.1.12	1.32

II.1.13 Offshore Construction/Installation

A. General

i)	Semi-Submersible Drilling Rig Contract For Dual Construction/ Drilling/Misc. Activity As Required Mob/Demob. from say Gulf of Mexico: 40 days @ $100,000 On Location 3 yrs. (Min.) @ $125,000 Including All Services	140.88
ii)	Survey Vessel (3 Seasons) Mob./Demob. from say East Coast Canada: 3 x 10 days = 30 days Operations : 3 x 180 days = 540 days Total = 570 days @ $30,000/day	17.10
iii)	Diving Spread (3 Seasons) Mob./Demob. from say Gulf of Mexico: 3 x 20 days = 60 days Operations : 3 x 180 days = 540 days Total = 600 days @ $80,000/day	48.00
iv)	Safety Vessels 1 in 1st Year; 2 in 2nd Year 3 in 3rd Year; 4 in 4th Year Total = 10 x 365 days @ $6,000/day	21.90

		Cost, $MM 1.1.82
v)	Supply Vessels 2 in 1st Two Years 4 in 2nd Two Years Total = 12 x 365 days @ $10,000/day	43.80
vi)	Helicopters 1st Year : 4 Trips Per Week 2nd Year : 8 Trips Per Week 3rd Year : 14 Trips Per Week 4th Year : 21 Trips Per Week 2,444 Trips of 3 Hrs. @ $3,000/hour	22.00
vii)	Allowance Against: Telecommunications; Catering; Fuels; Misc. Consumables; Operational Modifications	20.00
viii)	Allowance Against Bases and Depots for 4 Year Period	30.00
	Sub-Total A	343.68

B. Seabed Excavation

CMC's/FPP Riser Bases:
10 No. x 145,000 cu. yds.
Storage/Loading System Riser Bases:
4 No. x 122,000 cu. yds.

Assume Purpose Built Excavation Barge (Small Semi-Submersible) Using Clamshell Dredging System.

Assume Capital Cost = $50 MM Including Excavation Equipment, Contract Rate to Project @ $65,000/day Including All Services, etc.

	Cost, $MM 1.1.82
Assume System Excavates at 1,000 cu. yds/day with 40% Downtime During an 8-Month Weather Window, i.e., Approximately One Excavation Per Year Per Barge	
4 No. Barges Required Over 3 Seasons Plus 2 No. Next Season. Barges Laid-up East Coast Canada During Winter Months	
Operational Days: 3,230 days Laid-Up Days : 1,200 days 4,430 days @ $65,000/day	287.95
C. CMC/Riser Base Installation	
4 No. Installations Each in 2 Seasons	
2 No. Installations in 3rd Season	
i) Cargo Barge - Mob./Demob. from say Gulf of Mexico: 3 x 60 days = 180 days Operations - 2 x 120 days + 1 x 60 days = 300 days Total: 480 days @ $5,000/day	2.40
ii) Tugs (7,500 HP) 480 days: 2 x $10,000/day	9.60
iii) CMC/Riser Base Load-Out/Sea-Fastening (Assumed Structural Weight: 1,000 ton Each) 10 x 1,000 ton @ $100/ton	1.00

		Cost, $MM 1.1.82
iv)	Semi-Submersible Drill Rig (Available in Field - Refer Item 13A) Used For Installing CMC/Riser Bases By Keelhauling, Lowering, Drilling/Cementing Piles, Levelling Operating Days: 10 x 30 days = 300 days Additional Equipment, Hammers, Cement, etc. 300 days @ $50,000/day	15.00
	Sub-Total C	28.00
D.	FPP Anchor Piles	
	(Using Semi-Submersible, Survey Vessel and Supply Vessels Available In-Field) 4 No. FPP's x 12 piles x 4 day/pile = 192 days Additional Equipment, Hammers, Cement, etc. 192 days @ $50,000/day	9.60
E.	CMC - Riser Base Bundles (12 No.) and Satellite Well Bundles (16 No.)	
i)	Tow Out Tugs (2 No.) 28 No. x 7 days/bundle @ 2 x $10,000/day	3.92
ii)	Tie-Ins (Using Semi-Submersible, Diving/Survey Spread Available In-Field	--
iii)	Trenching (Using Trench Barge Mobilized for Submarine Gas Pipeline) 26.5 miles @ 1.5 mile/day = 18 days Downtime @ 50% = 18 days Total: 36 days @ $250,000/day	9.00
	Sub-Total E	12.92

		Cost, $MM
		1.1.82
F.	In-Field Transfer Lines	
i)	Laying (Using Laybarge Mobilized For Submarine Gas Pipeline) 35 miles @ 2.5 miles/day = 14 days Downtime @ 40% = 10 days Total 24 days @ $300,000/day	7.20
ii)	Pipe Supply 5 days @ $10,000/day	0.05
iii)	Trenching (Using Trench Barge Mobilized For Submarine Gas Pipeline) 35 miles @ 1.5 miles/day = 24 days Downtime @ 50% = 24 days Total: 48 days @ $250,000/day	12.00
	Sub-Total F	19.25
G.	Oil Storage/Export System	
i)	To Load-Out/Transport/Install Storage Tanker Mooring System (2 No.)	22.75
ii)	To Transport/Install Storage Tanker (2 No.)	9.10
iii)	To Load-Out/Transport/Install Shuttle Tanker Mooring Loading Terminal (2 No.)	22.75
	Sub-Total G	54.60

	Cost, $MM
	1.1.82
H. Floating Production Platforms	
Assume 2 FPP's Built in Canada 2 FPP's Foreign-Built	
i) Towage - 3 tugs per FPP Total Tug Charter - 228 days @ $10,000/day	2.28
ii) Mooring Line Running/Connection Made Using Tugs as Contracted Plus Survey/Diving Vessels Available In-Field Mooring Lines Fittings Included In FPP Cost	--
Sub-Total H	2.28
Sub-Total II.1.13	758.28
II.1.14 Management, Engineering, Commissioning	
A. Management, Supervision, Design, Engineering; 12%	317.07
B. Commissioning/Start-Up; 5%	132.11
C. Insurance; 3%	79.27
Sub-Total II.1.14	528.45
II.1.15 Contingency	
30%	951.20
TOTAL	4,121.88

II.2 SUBMARINE GAS PIPELINE

		Cost, $MM
		1.1.82
II.2.1	Materials	
	A. Line Pipe (260 mile + 5%; 24", API 5LX60) 186 lb/ft. @ $1,400/ton	167.57
	B. Valves, Fittings, Buckle Arrestors, etc. 5% of A	8.38
	C. Pipe Anodes, Wrap, Concrete Coat 1,441,440 ft. @ $20/ft.	28.83
	Sub-Total	204.78
II.2.2	Pre-Laying	
	A. Pipe Handling/Storage 1,441,440 ft. @ $10/ft.	14.41
	B. Detailed Route Survey Bathymetry, Side Scan Sonar, Bottom Profiler, Magnetometer, etc., Shallow Coring/Sampling, RCV/Submersible Inspection, Mapping/Report Preparation; 90 days @ $80,000/day Including Mob./Demob. from say East Coast Canada	7.20
	C. Seabed Rock Grading Allowance	20.00
	Sub-Total	41.61

Cost, $MM
1.1.82

II.2.3 Landfall

Site Acquisition and Survey; Pre-Trench Foreshore and Surf Zone; Prepare Shore Approach; Blast/Trench/Grade as Required; Supply/Establish Pipeline Pull-In Equipment; Supply/Install Pipeline Equipment (Isolation Valves, Control Systems, etc.); Pull-In/Tie-In Submarine Line and Landline; Restore Site 30.00

II.2.4 Pipelaying/Trenching

A. Large, Semi-Submersible Laybarge Spread

Layrate = 2 mile/day (average lay day)
Downtime for Weather, Mechanical Breakdown, Non-Productive Operations = 40%

Buckle Repairs: 1 "wet" @ 30 days
2 "dry" @ 10 days each

Laying Season: 180 days

Total Laydays: 130
Downtime: 87
Buckle Repairs: 50
Total Schedule: 267

Barge Required for 2 Seasons

Mob./Demob. from say North Sea:
2 x 50 days including Preparation

Thus: 367 days @ $300,000/day 110.10

	Cost, $MM 1.1.82
B. Pipe Supply Contract	
6 No. Pipe Carriers Mob./Demob. from say North Sea 2 Seasons @ 25 days each Total Charter = 317 days @ $10,000 Each	19.02
C. Trenching (Allowance Only)	
Trenching by Jetting to Typical Depth (say 3') Only Assumed Small Semi-Submersible Laybarge with Jet Sled and Services Length Trenched - 200 miles Trench Rate - 1.5 miles/day (Average Trenching Day) Downtime for Weather, Mechanical Breakdown, Non-Productive Operations = 50% Trenching Season: 180 days Total Trenching Days: 134 Downtime: 134 Total Schedule: 268 Barge Required for 2 Seasons Mob./Demob. from say North Sea 2 x 60 days including Preparation Thus: 388 days @ $250,000/day	97.00
Sub-Total	226.12

II.2.5 Post-Lay Survey/Remedial Work

	Cost, $MM 1.1.82
A. Post-Lay Survey	
Survey Vessel with Side Scan, Bottom Profiler Equipment, Diving Spread, RCV/Submersible; 60 days @ $80,000/days Including Mob./Demob. from say East Coast Canada	4.80
B. Remedial Work	
Re-Trenching, Free Span Reduction; Trench Backfill/Sand Bag/Rip-Rap As Required; Stabilization Devices/ Rock Anchors As Required (60 miles)	
Allowance: Trench/Remedial Work Barge, Supply Vessel; 90 days @ $250,000/day Materials/Rock Anchors; $20 MM	42.50
C. Post-Remedial Work Survey	
30 days @ $80,000/day	2.40
Sub-Total	49.70

	Cost, $MM 1.1.82
II.2.6 Tie-Ins	
Landfall Tie-In Included in Item 3 Subsea Tie-In to Hibernia South Riser Base (Using Semi-Submersible Available in Field);	
Tie-In Operations: 15 days @ $150,000/day	2.25
II.2.7 Management, Engineering, Commissioning	
A. Management, Supervision, Design, Engineering; 6%	33.27
B. Test/Commissioning/Start-Up; 2-1/2%	13.86
C. Insurance; 3%	16.63
Sub-Total	63.76
II.2.8 Contingency	
20%	123.64
TOTAL	741.86

		Cost, $MM 1.1.82
II.3	ONSHORE GAS LANDLINE	
II.3.1	Materials	
	A. Line Pipe (70 mile + 5%, 24", API 5LX 60) 186 lb./ft. @ $1,400/ton	45.11
	B. Valves, Fittings, Miscellaneous; 5% of A	2.26
	C. External/Internal Coating, Corrosion Protection; 388,080 ft. @ $7/ft.	2.72
	Sub-Total	50.09
II.3.2	Route Preparation	
	A. Right-of-Way, Damages, Survey (Allowance)	5.00
	B. Clearing, Access Roads; 70 miles @ $27,500/mile	1.93
	C. Common Grading/Culverts; 62 miles @ $40,000/mile	2.48
	D. Rock Grading; 8 miles @ $490,000/mile	3.92
	E. Rock Ditching; 60% of 70 miles @ $268,000/mile	11.26
	Sub-Total	24.59

		Cost, $MM 1.1.82
II.3.3	Pipelaying	
	A. Stockpiling Pipe; 388,080 ft. @ $5/ft.	1.94
	B. Pipelaying, Backfill and Test; 70 miles @ $560,000/mile	39.20
	C. Creek/River Crossings (40 No.) 40 No. @ $500,000 each	20.00
	D. Road/Railway Crossings; 7 No. @ $90,000 each	0.63
	Sub-Total	61.77
II.3.4	Management, Engineering, Commissioning	
	A. Management, Supervision, Design, Engineering; 6%	8.19
	B. Test/Commissioning/Start-Up; 2-1/2%	3.41
	C. Insurance; 2%	2.73
	Sub-Total	14.33
II.3.5	Contingency	
	10%	15.08
	TOTAL	165.86

II.4 GAS RECEPTION FACILITIES

		Cost, $MM 1.1.82
II.4.1	New Terminal at Long Harbour	
	Slug Catcher, Sphere/Pig Traps Valves, Control, Instrumentation Metering, Liquids Disposal Flare/Vent System Utilities, etc.	
	Supply/Construction/Installation	20.00
II.4.2	Management, Engineering, Commissioning	
	A. Management, Supervision, Design Engineering; 12%	2.40
	B. Commissioning/Start-Up; 5%	1.00
	C. Insurance; 2%	0.40
	Sub-Total	3.80
II.4.3	Contingency	
	20%	4.76
	TOTAL	28.56

APPENDIX III

CAPITAL COST BREAKDOWN - NORTHERN PIPELINE

VIA BAY BULLS LANDFALL

III.1 SUBMARINE GAS PIPELINE......... 1
III.2 ONSHORE GAS LANDLINE........... 6

APPENDIX III - CAPITAL COST BREAKDOWN - NORTHERN PIPELINE

VIA BAY BULLS LANDFALL

III.1 SUBMARINE GAS PIPELINE

	Cost, $MM 1.1.82
III.1.1 Materials	
A. Line Pipe (195 mile + 5%; 24", API 5LX60) 186 lb/ft. @ $1,400/ton	125.68
B. Valves, Fittings, Buckle Arrestors, etc. 5% of A	6.28
C. Pipe Anodes, Wrap, Concrete Coat 1,081,080 ft. @ $20/ft.	21.62
Sub-Total	153.58
III.1.2 Pre-Laying	
A. Pipe Handling/Storage 1,081,080 ft. @ $10/ft.	10.81
B. Detailed Route Survey Bathymetry, Side Scan Sonar, Bottom Profiler, Magnetometer, etc., Shallow Coring/Sampling, RCV/Submersible Inspection, Mapping/Report Preparation; 70 days @ $80,000/day Including Mob./Demob. from say East Coast Canada	5.60
C. Seabed Rock Grading Allowance	30.00
Sub-Total	46.41

Cost, $MM
1.1.82

III.1.3 Landfall

Site Acquisition and Survey; Pre-Trench Foreshore and Surf Zone; Prepare Shore Approach; Blast/Trench/Grade as Required; Supply/Establish Pipeline Pull-In Equipment; Supply/Install Pipeline Equipment (Isolation Valves, Control Systems, etc.); Pull-In/Tie-In Submarine Line and Landline; Restore Site 30.00

III.1.4 Pipelaying/Trenching

A. Large, Semi-Submersible Laybarge Spread

Layrate = 2 mile/day (average lay day)
Downtime for Weather, Mechanical Breakdown, Non-Productive Operations = 40%

Buckle Repairs: 1 "wet" @ 30 days
2 "dry" @ 10 days each

Laying Season: 180 days

Total Laydays: 98
Downtime: 65
Buckle Repairs: 50
Total Schedule: 213

Barge Required for 2 Seasons

Mob./Demob. from say North Sea:
2 x 50 days including Preparation

Thus: 313 days @ $300,000/day 93.90

	Cost, $MM
	1.1.82
B. Pipe Supply Contract	
4 No. Pipe Carriers	
Mob./Demob. from say North Sea	
2 Seasons @ 25 days each	
Total Charter = 263 days @ $10,000 Each	10.52
C. Trenching (Allowance Only)	
Trenching by Jetting to Typical Depth (say 3') Only Assumed	
Small Semi-Submersible Laybarge with Jet Sled and Services	
Length Trenched - 97.5 miles	
Trench Rate - 1.5 miles/day (Average Trenching Day)	
Downtime for Weather, Mechanical Breakdown, Non-Productive Operations = 50%	
Trenching Season: 180 days	
Total Trenching Days: 65	
Downtime: 65	
Total Schedule: 130	
Barge Required for 1 Season	
Mob./Demob. from say North Sea	
1 x 60 days including Preparation	
Thus: 190 days @ $250,000/day	47.50
Sub-Total	151.92

III.1.5 Post-Lay Survey/Remedial Work

	Cost, $MM 1.1.82
A. Post-Lay Survey	
Survey Vessel with Side Scan, Bottom Profiler Equipment, Diving Spread, RCV/Submersible; 60 days @ $80,000/days Including Mob./Demob. from say East Coast Canada	4.80
B. Remedial Work	
Re-Trenching, Free Span Reduction; Trench Backfill/Sand Bag/Rip-Rap As Required; Stabilization Devices/ Rock Anchors As Required (97.5 miles) Allowance: Trench/Remedial Work Barge, Supply Vessel; 45 days; Mob./Demob. from say North Sea; 1 x 60 days including Preparation Total: 105 days @ $250,000/day Materials/Rock Anchors; $30 MM	56.25
C. Post-Remedial Work Survey	
30 days @ $80,000/day	2.40
Sub-Total	63.45

	Cost, $MM 1.1.82
III.1.6 Tie-Ins	
Landfall Tie-In Included in Item 3 Subsea Tie-In to Hibernia South Riser Base (Using Semi-Submersible Available in Field);	
Tie-In Operations: 15 days @ $150,000/day	2.25
III.1.7 Management, Engineering, Commissioning	
A. Management, Supervision, Design, Engineering; 6%	26.86
B. Test/Commissioning/Start-Up; 2-1/2%	11.19
C. Insurance; 3%	13.43
Sub-Total	51.48
III.1.8 Contingency	
20%	99.82
TOTAL	598.91

III.2 ONSHORE GAS LANDLINE

III.2.1 Materials

	Cost, $MM 1.1.82
A. Line Pipe (55 mile + 5%, 24", API 5LX 60) 186 lb./ft. @ $1,400/ton	35.45
B. Valves, Fittings, Miscellaneous; 5% of A	1.77
C. External/Internal Coating, Corrosion Protection; 304,920 ft. @ $7/ft.	2.13
Sub-Total	39.35

III.2.2 Route Preparation

A. Right-of-Way, Damages, Survey (Allowance)	4.00
B. Clearing, Access Roads; 55 miles @ $27,500/mile	1.51
C. Common Grading/Culverts; 48.7 miles @ $40,000/mile	1.95
D. Rock Grading; 6.3 miles @ $490,000/mile	3.09
E. Rock Ditching; 60% of 55 miles @ $268,000/mile	8.84
Sub-Total	19.39

	Cost, $MM 1.1.82
III.2.3 Pipelaying	
A. Stockpiling Pipe; 304,920 ft. @ $5/ft.	1.52
B. Pipelaying, Backfill and Test; 55 miles @ $560,000/mile	30.80
C. Creek/River Crossings (40 No.) 25 No. @ $500,000 each	12.50
D. Road/Railway Crossings; 5 No. @ $90,000 each	0.45
Sub-Total	45.27
III.2.4 Management, Engineering, Commissioning	
A. Management, Supervision, Design, Engineering; 6%	6.24
B. Test/Commissioning/Start-Up; 2-1/2%	2.60
C. Insurance; 2%	2.08
Sub-Total	10.92
III.2.5 Contingency	
10%	11.49
TOTAL	126.42

POOR

QUALITY

ORIGINAL